NEW SOURCE CONSTRUCTION PERMIT
Prevention of Significant Deterioration (PSD) Permit
Office of Air Quality

Duke Energy Knox, LLC
Corner of SE 1275 E and SE 300 S
Wheatland, Indiana

(herein known as the Permittee) is hereby authorized to construct and operate subject to the conditions contained herein, the emission units described in Section A (Source Summary) of this permit.

This permit is issued to the above mentioned company under the provisions of 326 IAC 2-1.1, 326 IAC 2-5.1, 326 IAC 2-6.1 and 40 CFR 52.780, with conditions listed on the attached pages.

This permit is also issued under the provisions of 326 IAC 2-2, 40 CFR 52.21, and 40 CFR 52.124 (Prevention of Significant Deterioration), with conditions listed on the attached pages.

Construction Permit No.: CP 083-12674-00043	
Issued by: Paul Dubenetzky, Branch Chief Office of Air Quality	Issuance Date:

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SECTION A SOURCE SUMMARY

This permit is based on information requested by the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ). The information describing the source contained in conditions A.1 through A.3 is descriptive information and does not constitute enforceable conditions. However, the Permittee should be aware that a physical change or a change in the method of operation that may render this descriptive information obsolete or inaccurate may trigger requirements for the Permittee to obtain additional permits or seek modification of this permit pursuant to 326 IAC 2, or change other applicable requirements presented in the permit application.

A.1 General Information [326 IAC 2-5.1-3(c)] [326 IAC 2-6.1-4(a)]

The Permittee owns and operates a simple cycle merchant electric power plant.

Authorized Individual:	Kenneth S. Johnson
Source Address:	Corner of SE 1275 E and SE 300 S, Wheatland, IN 47597
Mailing Address:	5400 Westheimer Court Houston, TX 77056-5310
Phone Number:	(713)-627-6500
SIC Code:	4911
County Location:	Knox
County Status:	Attainment for all Criteria Pollutants
Source Status:	Major, under PSD rules

A.2 Emissions units and Pollution Control Equipment Summary

This stationary source is approved to construct and operate the following emissions units and pollution control devices:

(a) Eight (8) General Electric 7EA simple cycle, natural gas-fired combustion turbine generators, designated as units CTG1-CTG8, with a maximum heat input capacity of 1158 MMBtu/hr each and a nominal output of 80 MW each, exhausting to stacks designated as #1-#8. The nitrogen oxide emissions are controlled by dry low-NO_X combustors.

(b) One (1) emergency diesel fire pump, designated as unit #9, with a maximum heat input capacity of 1.6 MMBtu/hr and exhausts to a stack designated as #9.

(c) Four (4) diesel fuel storage tanks, designated as tans #1-#4, with a maximum capacity of 520,000 gallons per tank, a maximum of 84,650 ft^3 per tank.

A.3 Part 70 Permit Applicability [326 IAC 2-7-2]

This stationary source is required to have a Part 70 permit by 326 IAC 2-7-2 (Applicability) because:

(a) It is a major source, as defined in 326 IAC 2-7-1(22);

(b) It is an affected source under Title IV (Acid Deposition Control) of the Clean Air Act, as defined in 326 IAC 2-7-1(3);

(c) It is a source in a source category designated by the United States Environmental Protection Agency (U.S. EPA) under 40 CFR 70.3 (Part 70 - Applicability).

A.4 Acid Rain Permit Applicability [326 IAC 2-7-2]

This stationary source shall be required to have a Phase II, Acid Rain permit by 40 CFR 72.30 (Applicability) because:

(a) The combustion turbines are new units under 40 CFR 72.6.

(b) The source cannot operate the combustion units until their Phase II, Acid Rain permit has been issued.

SECTION B GENERAL CONSTRUCTION CONDITIONS

THIS SECTION OF THE PERMIT IS BEING ISSUED UNDER THE PROVISIONS OF 326 IAC 2-1.1 AND 40 CFR 52.780, WITH CONDITIONS LISTED BELOW.

B.1 Permit No Defense [IC 13]

This permit to construct does not relieve the Permittee of the responsibility to comply with the provisions of the Indiana Environmental Management Law (IC 13-11 through 13-20; 13-22 through 13-25; and 13-30), the Air Pollution Control Law (IC 13-17) and the rules promulgated thereunder, as well as other applicable local, state, and federal requirements.

B.2 Definitions

Terms in this permit shall have the definition assigned to such terms in the referenced regulation. In the absence of definitions in the referenced regulation, any applicable definitions found in IC 13-11, 326 IAC 1-2, and 326 IAC 2-1.1-1 shall prevail.

B.3 Effective Date of the Permit [40 CFR 124]

Pursuant to 40 CFR 124.15, 40 CFR 124.19, and 40 CFR 124.20, this permit is effective immediately after the service of notice of the decision, except as provided in 40 CFR 124. Three (3) days shall be added if service of notice is by mail.

B.4 Revocation of Permits [326 IAC 2-2-8]

Pursuant to 326 IAC 2-2-8(a)(1) and 40 CFR 52.21, this permit to construct shall expire if construction is not commenced within eighteen (18) months after receipt of this approval or if construction is discontinued for a period of eighteen (18) months or more.

B.5 First Time Operation Permit [326 IAC 2-6.1]

This document shall also become a first time operating permit pursuant to 326 IAC 2-5.1-3 when, prior to start of operation, the following requirements are met:

(a) Any modifications required by 326 IAC 2-1.1 and 326 IAC 2-7-10.5 as a result of a change in the design or operation of emissions units described by this permit have been obtained prior to obtaining an Operation Permit Validation Letter.

(b) The attached Affidavit of Construction shall be submitted to the Office of Air Quality (OAQ), Permit Administration & Development Section.

(1) If the Affidavit of Construction verifies that the facilities covered in this Construction Permit were constructed as proposed in the application, then the facilities may begin operating on the date the Affidavit of Construction is postmarked or hand delivered to IDEM.

(2) If the Affidavit of Construction does not verify that the facilities covered in this Construction Permit were constructed as proposed in the application, then the Permittee shall receive an Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section prior to beginning operation of the facilities.

(c) If construction is completed in phases; i.e., the entire construction is not done continuously, a separate affidavit must be submitted for each phase of construction. Any permit conditions associated with operation start up dates such as stack testing for New Source Performance Standards (NSPS) shall be applicable to each individual phase.

(d) Upon receipt of the Operation Permit Validation Letter from the Chief of the Permit Administration & Development Section, the Permittee shall attach it to this document.

(e) The operation permit will be subject to annual operating permit fees pursuant to 326 IAC 2-7-19 (Fees).

(f) Pursuant to 326 IAC 2-7-4(a)(1)(A)(ii) and 326 IAC 2-5.1-4, the Permittee shall apply for a Title V operating permit within twelve (12) months of the date on which the source first meets an applicability criterion of 326 IAC 2-7-2.

B.6 NSPS Reporting Requirement

Pursuant to the New Source Performance Standards (NSPS), Part 60.7, Part 60.8, the source owner/operator is hereby advised of the requirement to report the following at the appropriate times:

(a) Commencement of construction date (no later than 30 days after such date);

(b) Anticipated start-up date (not more than 60 days or less than 30 days prior to such date);

(c) Actual start-up date (within 15 days after such date); and

(d) Date of performance testing (at least 30 days prior to such date), when required by a condition elsewhere in this permit.

Reports are to be sent to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue P.O. Box 6015
Indianapolis, IN 46206-6015

The application and enforcement of these standards have been delegated to the IDEM, OAQ. The requirements of 40 CFR Part 60 are also federally enforceable.

SECTION C SOURCE OPERATION CONDITIONS

Entire Source

C.1 Major Source

Pursuant to 326 IAC 2-2 (Prevention of Significant Deterioration) and 40 CFR 52.21, and 326 IAC 2-7 (Part 70 Permit Program), this source is a major source.

C.2 Preventive Maintenance Plan [326 IAC 1-6-3]

(a) If required by specific condition(s) in Section D of this permit, the Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) ninety (90) days after the commencement of normal operations after the first construction phase, including the following information on each emissions unit:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission control devices;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that failure to implement the Preventive Maintenance Plan does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. IDEM, OAQ may require the Permittee to revise its Preventive Maintenance Plan whenever lack of proper maintenance causes or contributes to any violation.

C.3 Source Modification [326 IAC 2-7-10.5]

(a) The Permittee must comply with the requirements of 326 IAC 2-7-10.5 whenever the Permittee seeks to construct new emissions units, modify existing emissions units, or otherwise modify the source.

(b) Any application requesting an amendment or modification of this permit shall be submitted to:

Indiana Department of Environmental Management
Permits Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015

Any such application should be certified by the "responsible official" as defined by 326 IAC 2-7-1(34) only if a certification is required by the terms of the applicable rule.

C.4 Inspection and Entry [326 IAC 2-5.1-3(e)(4)(B)] [326 IAC 2-6.1-5(a)(4)]

Upon presentation of proper identification cards, credentials, and other documents as may be required by law, and subject to the Permittee's right under all applicable laws and regulations to assert that the information collected by the agency is confidential and entitled to be treated as such, the Permittee shall allow IDEM, OAQ, U.S. EPA, or an authorized representative to perform the following:

(a) Enter upon the Permittee's premises where a permitted source is located, or emissions related activity is conducted, or where records must be kept under the conditions of this permit;

(b) Have access to and copy, at reasonable times, any records that must be kept under this title or the conditions of this permit or any operating permit revisions;

(c) Inspect, at reasonable times, any processes, emissions units (including monitoring and air pollution control equipment), practices, or operations regulated or required under this permit or any operating permit revisions;

(d) Sample or monitor, at reasonable times, substances or parameters for the purpose of assuring compliance with this permit or applicable requirements; and

(e) Utilize any photographic, recording, testing, monitoring, or other equipment for the purpose of assuring compliance with this permit or applicable requirements.

C.5 Transfer of Ownership or Operation [326 IAC 2-6.1-6(d)(3)]

Pursuant to [326 IAC 2-6.1-6(d)(3)]

(a) In the event that ownership of this source is changed, the Permittee shall notify IDEM, OAQ, Permits Branch, within thirty (30) days of the change.

(b) The written notification shall be sufficient to transfer the permit to the new owner by a notice-only change pursuant to 326 IAC 2-6.1-6(d)(3).

(c) IDEM, OAQ shall issue a revised permit.

The notification which shall be submitted by the Permittee does require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

C.6 Permit Revocation [326 IAC 2-1-9]

Pursuant to 326 IAC 2-1-9(a)(Revocation of Permits), this permit to construct and operate may be revoked for any of the following causes:

(a) Violation of any conditions of this permit.

(b) Failure to disclose all the relevant facts, or misrepresentation in obtaining this permit.

(c) Changes in regulatory requirements that mandate either a temporary or permanent reduction of discharge of contaminants. However, the amendment of appropriate sections of this permit shall not require revocation of this permit.

(d) Noncompliance with orders issued pursuant to 326 IAC 1-5 (Episode Alert Levels) to reduce emissions during an air pollution episode.

(e) For any cause which establishes in the judgment of IDEM the fact that continuance of this permit is not consistent with purposes of this article.

C.7 Opacity [326 IAC 5-1]

Pursuant to 326 IAC 5-1-2 (Opacity Limitations), except as provided in 326 IAC 5-1-3 (Temporary Alternative Opacity Limitations), opacity shall meet the following, unless otherwise stated in this permit:

(a) Opacity shall not exceed an average of forty percent (40%) in any one (1) six (6) minute averaging period as determined in 326 IAC 5-1-4.

(b) Opacity shall not exceed sixty percent (60%) for more than a cumulative total of fifteen (15) minutes, sixty (60) readings as measured according to 40 CFR 60, Appendix A, Method 9 or fifteen (15) one (1) minute non-overlapping integrated averages for a continuous opacity) monitor in a six (6) hour period.

C.8 Fugitive Dust Emissions [326 IAC 6-4]

The Permittee shall not allow fugitive dust to escape beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located, in a manner that would violate 326 IAC 6-4 (Fugitive Dust Emissions). 326 IAC 6-4-2(4) is not federally enforceable.

C.9 Stack Height [326 IAC 1-7]

The Permittee shall comply with the applicable provisions of 326 IAC 1-7 (Stack Height Provisions), for all exhaust stacks through which a potential (before controls) of twenty-five (25) tons per year or more of particulate matter or sulfur dioxide is emitted by using good engineering practices (GEP) pursuant to 326 IAC 1-7-3.

Testing Requirements

C.10 Performance Testing [326 IAC 3-6]

(a) Compliance testing on new emissions units shall be conducted within 60 days after achieving maximum production rate, but no later than 180 operating days after initial start-up, if specified in Section D of this approval. All testing shall be performed according to the provisions of 326 IAC 3-6 (Source Sampling Procedures), except as provided elsewhere in this permit, utilizing any applicable procedures and analysis methods specified in 40 CFR 51, 40 CFR 60, 40 CFR 61, 40 CFR 63, 40 CFR 75, or other procedures approved by IDEM, OAQ.

A test protocol, except as provided elsewhere in this permit, shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

no later than thirty-five (35) days prior to the intended test date. The Permittee shall submit a notice of the actual test date to the above address so that it is received at least two weeks prior to the test date.

(b) IDEM, OAQ must receive all test reports within forty-five (45) days after the completion of the testing. IDEM, OAQ may grant an extension, if the source submits to IDEM, OAQ reasonable written explanation within five (5) days prior to the end of the initial forty-five (45) day period.

The documentation submitted by the Permittee does not require certification by the “authorized individual” as defined by 326 IAC 2-1.1-1.

Compliance Monitoring Requirements

C.11 Compliance Monitoring [326 IAC 2-1.1-11]

Compliance with applicable requirements shall be documented as required by this permit. The Permittee shall be responsible for installing any necessary equipment and initiating any required monitoring related to that equipment. All monitoring and record keeping requirements not already legally required shall be implemented when operation begins.

C.12 Maintenance of Monitoring Equipment [IC 13-14-1-13]

(a) In the event that a breakdown of the monitoring equipment occurs, a record shall be made of the times and reasons of the breakdown and efforts made to correct the problem. To the extent practicable, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less frequent than required in Section D of this permit until such time as the monitoring equipment is back in operation. In the case of continuous monitoring, supplemental or intermittent monitoring of the parameter should be implemented at intervals no less than one (1) hour until such time as the continuous monitor is back in operation.

(b) The Permittee shall install, calibrate, quality assure, maintain, and operate all necessary monitors and related equipment. In addition, prompt corrective action shall be initiated whenever indicated.

C.13 Monitoring Methods [326 IAC 3]

Any monitoring or testing required by Section D of this permit shall be performed according to the provisions of 326 IAC 3, 40 CFR 60, Appendix A, or other approved methods as specified in this permit.

C.14 Compliance Monitoring Plan - Failure to Take Response Steps [326 IAC 1-6] [326 IAC 2-2-4]

(a) The Permittee is required to implement a compliance monitoring plan to ensure that reasonable information is available to evaluate its continuous compliance with applicable requirements. This compliance monitoring plan is comprised of:

(1) This condition;

(2) The Compliance Determination Requirements in Section D of this permit;

(3) The Compliance Monitoring Requirements in Section D of this permit;

(4) The Record Keeping and Reporting Requirements in Section C (Monitoring Data Availability, General Record Keeping Requirements, and General Reporting Requirements) and in Section D of this permit; and

(5) A Compliance Response Plan (CRP) for each compliance monitoring condition of this permit. CRP's shall be submitted to IDEM, OAQ upon request and shall be subject to review and approval by IDEM, OAQ. The CRP shall be prepared within ninety (90) days after the commencement of normal operation after the first phase of construction and shall be maintained on site, and is comprised of:

(A) Response steps that will be implemented in the event that compliance related information indicates that a response step is needed pursuant to the requirements of Section D of this permit; and

(B) A time schedule for taking such response steps including a schedule for devising additional response steps for situations that may not have been predicted.

(b) For each compliance monitoring condition of this permit, appropriate response steps shall be taken when indicated by the provisions of that compliance monitoring condition. Failure to perform the actions detailed in the compliance monitoring conditions or failure to take the response steps within the time prescribed in the Compliance Response Plan, shall constitute a violation of the permit unless taking the response steps set forth in the Compliance Response Plan would be unreasonable.

(c) After investigating the reason for the excursion, the Permittee is excused from taking further response steps for any of the following reasons:

(1) The monitoring equipment malfunctioned, giving a false reading. This shall be an excuse from taking further response steps providing that prompt action was taken to correct the monitoring equipment.

(2) The Permittee has determined that the compliance monitoring parameters established in the permit conditions are technically inappropriate, has previously submitted a request for an administrative amendment to the permit, and such request has not been denied or;

(3) An automatic measurement was taken when the process was not operating; or

(4) The process has already returned to operating within "normal" parameters and no response steps are required.

(d) Records shall be kept of all instances in which the compliance related information was not met and of all response steps taken.

C.15 Actions Related to Noncompliance Demonstrated by a Stack Test

(a) When the results of a stack test performed in conformance with Section C - Performance Testing, of this permit exceed the level specified in any condition of this permit, the Permittee shall take appropriate corrective actions. The Permittee shall submit a description of these corrective actions to IDEM, OAQ within thirty (30) days of receipt of the test results. The Permittee shall take appropriate action to minimize emissions from the affected emissions unit while the corrective actions are being implemented. IDEM, OAQ shall notify the Permittee within thirty (30) days, if the corrective actions taken are deficient. The Permittee shall submit a description of additional corrective actions taken to IDEM, OAQ within thirty (30) days of receipt of the notice of deficiency. IDEM, OAQ reserve the authority to use enforcement activities to resolve noncompliant stack tests.

(b) A retest to demonstrate compliance shall be performed within one hundred twenty (120) days of receipt of the original test results. Should the Permittee demonstrate to IDEM, OAQ that retesting in one hundred and twenty (120) days is not practicable, IDEM, OAQ may extend the retesting deadline. Failure of the second test to demonstrate compliance with the appropriate permit conditions may be grounds for immediate revocation of the permit to operate the affected emissions unit.

The documents submitted pursuant to this condition do not require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1.

Record Keeping and Reporting Requirements

C.16 Malfunctions Report [326 IAC 1-6-2]

Pursuant to 326 IAC 1-6-2 (Records; Notice of Malfunction):

(a) A record of all malfunctions, including startups or shutdowns of any facility or emission control equipment, which result in violations of applicable air pollution control regulations or applicable emission limitations shall be kept and retained for a period of three (3) years and shall be made available to the Indiana Department of Environmental Management (IDEM), Office of Air Quality (OAQ), or appointed representative upon request.

(b) When a malfunction of any facility or emission control equipment occurs which lasts more than one (1) hour, said condition shall be reported to OAQ using the Malfunction Report Forms (2 pages). Notification shall be made by telephone or facsimile, as soon as practicable, but in no event later than four (4) daytime business hours after the beginning of said occurrence.

(c) Failure to report a malfunction of any emission control equipment shall constitute a violation of 326 IAC 1-6, and any other applicable rules. Information of the scope and expected duration of the malfunction shall be provided, including the items specified in 326 IAC 1-6-2(a)(1) through (6).

(d) Malfunction is defined as any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner. [326 IAC 1-2-39]

C.17 Monitoring Data Availability [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) With the exception of performance tests conducted in accordance with Section C-Performance Testing, all observations, sampling, maintenance procedures, and record keeping, required as a condition of this permit shall be performed at all times the equipment is operating at normal representative conditions.

(b) As an alternative to the observations, sampling, maintenance procedures, and record keeping of subsection (a) above, when the equipment listed in Section D of this permit is not operating, the Permittee shall either record the fact that the equipment is shut down or perform the observations, sampling, maintenance procedures, and record keeping that would otherwise be required by this permit.

(c) If the equipment is operating but abnormal conditions prevail, additional observations and sampling should be taken with a record made of the nature of the abnormality.

(d) If for reasons beyond its control, the operator fails to make required observations, sampling, maintenance procedures, or record keeping, reasons for this must be recorded.

(e) At its discretion, IDEM may excuse such failure providing adequate justification is documented and such failures do not exceed five percent (5%) of the operating time in any quarter.

(f) Temporary, unscheduled unavailability of staff qualified to perform the required observations, sampling, maintenance procedures, or record keeping shall be considered a valid reason for failure to perform the requirements stated in (a) above.

C.18 General Record Keeping Requirements [326 IAC 2-6.1-2]

(a) Records of all required monitoring data and support information shall be retained for a period of at least five (5) years from the date of monitoring sample, measurement, report, or application. These records shall be kept at the source location for a minimum of three (3) years and available upon the request of an IDEM, OAQ representative. The records may be stored elsewhere for the remaining two (2) years as long as they are available upon request. If the Commissioner or makes a written request for records to the Permittee, the Permittee shall furnish the records to the Commissioner or within a reasonable time.

(b) Records of required monitoring information shall include, where applicable:

(1) The date, place, and time of sampling or measurements;

(2) The dates analyses were performed;

(3) The company or entity performing the analyses;

(4) The analytic techniques or methods used;

(5) The results of such analyses; and

(6) The operating conditions existing at the time of sampling or measurement.

(c) Support information shall include, where applicable:

(1) Copies of all reports required by this permit;

(2) All original strip chart recordings for continuous monitoring instrumentation;

(3) All calibration and maintenance records;

(4) Records of preventive maintenance shall be sufficient to demonstrate that failure to implement the Preventive Maintenance Plan did not cause or contribute to a violation of any limitation on emissions or potential to emit. To be relied upon subsequent to any such violation, these records may include, but are not limited

to: work orders, parts inventories, and operator's standard operating procedures. Records of response steps taken shall indicate whether the response steps were performed in accordance with the Compliance Response Plan required by Section C - Compliance Monitoring Plan - Failure to take Response Steps, of this permit, and whether a deviation from a permit condition was reported. All records shall briefly describe what maintenance and response steps were taken and indicate who performed the tasks.

(d) All record keeping requirements not already legally required shall be implemented when operation begins.

C.19 General Reporting Requirements [326 IAC 2-1.1-11] [326 IAC 2-6.1-2] [IC 13-14-1-13]

(a) To affirm that the source has met all the compliance monitoring requirements stated in this permit the source shall submit a Semi-annual Compliance Monitoring Report. Any deviation from the requirements and the date(s) of each deviation must be reported. The Compliance Monitoring Report shall include the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(b) The report required in (a) of this condition and reports required by conditions in Section D of this permit shall be submitted to:

Indiana Department of Environmental Management
Compliance Data Section, Office of Air Quality
100 North Senate Avenue, P. O. Box 6015
Indianapolis, Indiana 46206-6015

(c) Unless otherwise specified in this permit, any notice, report, or other submission required by this permit shall be considered timely if the date postmarked on the envelope or certified mail receipt, or affixed by the shipper on the private shipping receipt, is on or before the date it is due. If the document is submitted by any other means, it shall be considered timely if received by IDEM, OAQ on or before the date it is due.

(d) Unless otherwise specified in this permit, any semi-annual report shall be submitted within thirty (30) days of the end of the reporting period. The reports require the certification by the "authorized individual" as defined by 326 IAC 2-1.1-1(1).

(e) All instances of deviations must be clearly identified in such reports. A reportable deviation is an exceedance of a permit limitation or a failure to comply with a requirement of the permit or a rule. It does not include:

(1) An excursion from compliance monitoring parameters as identified in Section D of this permit unless tied to an applicable rule or limit; or

(2) A malfunction as described in 326 IAC 1-6-2; or

(3) Failure to implement elements of the Preventive Maintenance Plan unless lack of maintenance has caused or contributed to a deviation.

(4) Failure to make or record information required by the compliance monitoring provisions of Section D unless such failure exceeds 5% of the required data in any calendar quarter.

A Permittee's failure to take the appropriate response step when an excursion of a compliance monitoring parameter has occurred or failure to monitor or record the required compliance monitoring is a deviation.

(f) Any corrective actions or response steps taken as a result of each deviation must be clearly identified in such reports.

(g) The first report shall cover the period commencing on the date start of normal operation after the first phase of construction and ending on the last day of the reporting period.

SECTION D.1 FACILITY CONDITIONS – Simple Cycle Operation

(a) Eight (8) General Electric 7EA simple cycle, natural gas-fired combustion turbine generators, designated as units CTG1-CTG8, with a maximum heat input capacity of 1158 MMBtu/hr each and a nominal output of 80 MW each, exhausting to stacks designated as #1-#8. The nitrogen oxide emissions are controlled by dry low-NO_X combustors.

(b) One (1) emergency diesel fire pump, designated as unit #9, with a maximum heat input capacity of 1.6 MMBtu/hr and exhausts to a stack designated as #9.

(c) Four (4) diesel fuel storage tanks, designated as tans #1-#4, with a maximum capacity of 520,000 gallons per tank, a maximum of 84,650 ft^3 per tank.

(The information describing the process contained in this facility description box is descriptive information, and does not constitute enforceable conditions.)

Emission Limitations and Standards

D.1.1 Prevention of Significant Deterioration [326 IAC 2-2]

Pursuant to 326 IAC 2-2 (PSD), this new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X, and VOC because the potential to emit for these pollutants exceed the PSD major significant thresholds. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standards (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

D.1.2 Particulate Matter (PM and PM_{10}) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), the total PM emissions from each combustion turbine shall comply with the following, excluding startup/shutdown emissions:

(1) When firing natural gas each turbine shall not exceed 0.0095 pounds per MMBtu on a higher heating value basis, which is equivalent to eleven (11) pounds per hour for each combustion turbine.

(2) When firing diesel fuel each turbine shall not exceed 0.0216 pounds per MMBtu, which is equivalent to 25.01 pounds per hour for each combustion turbine.

(3) Perform good combustion practice.

(4) The total PM is the sum of PM (filterable) and PM_{10} (filterable and condensible)

D.1.3 Opacity Limitations

Pursuant to 326 IAC 2-2 (PSD Requirements) the opacity from each associated combustion turbine stack shall not exceed twenty (20) percent (6-minute average), except for one 6-minute period per hour of not more than 27 percent. The opacity standards apply at all times, except during periods of startup, shutdown or malfunction. This satisfies the opacity limitations required by 326 IAC 5-1 (Opacity Limitations).

D.1.4 Startup and Shutdown Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), a startup or shutdown is defined as less than sixty (60) percent load. Each combustion turbine-generating unit shall comply with the following:

(a) The maximum number of startup/shutdowns shall not exceed 240 startup/shutdowns per twelve (12) month consecutive period. A startup or shutdown period shall not exceed one (1) hour.

(b) The NO_X emissions from each combustion turbine stack shall not exceed 20.7 pounds per startup and 11 pounds per shutdown when firing natural gas. Each combustion turbine stack shall not exceed 31.6 pounds per startup and 17.5 pounds per shutdown when firing diesel fuel. Each combustion turbine shall not exceed 4.3 tons per year of startup and shutdown emissions.

(c) The CO emissions from each combustion turbine stack shall not exceed 65.5 pounds per startup and 58.9 pounds per shutdown when firing natural gas. Each combustion turbine stack shall not exceed 76.4 pounds per startup and 65.5 pounds per shutdown when firing diesel fuel. Each combustion turbine shall not exceed 15.4 tons per year of startup and shutdown emissions.

D.1.5 Nitrogen Oxides (NO_X) Emission Limitations for Combustion Turbines

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine generating unit shall comply with the following, excluding startup and shutdown emissions:

(1) Use dry low-NO_X combustors in conjunction with natural gas.

(2) Use water injection in conjunction with diesel fuel.

(3) During normal simple cycle operation (sixty (60) percent load or more), the NO_X emissions from each combustion turbine when burning natural gas shall not exceed 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 31.96 pounds per hour for each combustion turbine.

(4) During normal simple cycle operation (sixty (60) percent load or more), the NO_X emissions from each combustion turbine when burning diesel fuel shall not exceed 42 ppmvd corrected to fifteen (15) percent oxygen, based on one (1) averaging period, which is equivalent to 166.98 pounds per hour for each combustion turbine.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the combined annual NO_X emissions from each of the eight (8) combustion turbines when burning natural gas and diesel fuel, shall not exceed 73.71 tons per year. However, each of the eight combustion turbines shall not exceed 41.75 tons per year of NO_X when firing only diesel fuel.

D.1.6 Carbon Monoxide (CO) Emission Limitations for Combustion Turbines

(a) Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine shall comply with the following, excluding startup and shutdown emissions:

(1) During normal simple cycle operation (sixty (60) percent load or more), the CO emissions from each combustion turbine, when burning natural gas, shall not exceed 25 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 53.96 pounds per hour from each combustion turbine.

(2) During normal simple cycle operation (sixty (60) percent load or more), the CO emissions from each combustion turbine, when burning diesel fuel, shall not exceed 25 ppmvd corrected to fifteen (15) percent oxygen, based on a one (1) hour averaging period, which is equivalent to 42.96 pounds per hour from each combustion turbine.

(3) Good combustion practices shall be applied to minimize CO emissions.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the combined annual CO emissions from each of the eight (8) combustion turbines when burning natural gas and diesel fuel, shall not exceed 67.45 tons per year. However, each of the eight combustion turbines shall not exceed 10.74 tons per year of CO when firing only diesel fuel.

D.1.7 Sulfur Dioxide (SO_2) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 2-2 (PSD Requirements), each combustion turbine shall comply with the following, excluding startup and shutdown emissions:

(1) During normal simple cycle operation (sixty (60) percent load or more), the SO_2 emissions from each combustion turbine, when firing natural gas, shall not exceed 0.0052 pounds per MMBtu on a higher heating values basis, which is equivalent to 6.02 pounds per hour from each combustion turbine.

(2) During normal simple cycle operation (sixty (60) percent load or more), the SO_2 emissions from each combustion turbine, when firing diesel fuel, shall not exceed 0.0363 pounds per MMBtu on a higher heating values basis, which is equivalent to 42.04 pounds per hour from each combustion turbine.

(3) The use of low sulfur natural gas as the primary fuel for the eight (8) combustion turbines. The sulfur content of the natural gas shall not exceed 0.8 percent by weight (two (2) grains per 100 scf)

(4) Use only diesel fuel as a back-up fuel source. The sulfur content of the diesel fuel shall not exceed 0.05 percent by weight

(5) Perform good combustion practices.

D.1.8 Volatile Organic Compound (VOC) Emission Limitations for Combustion Turbines

Pursuant to 326 IAC 8-1-6 (VOC BACT Requirements), the following requirements must be met, excluding startup and shutdown emissions:

(1) During normal simple cycle operation (sixty (60) percent load or more), the VOC emissions form each combustion turbine, when firing natural gas, shall not exceed 0.0018 pounds per MMBtu on a higher heating value basis, which is equivalent to 2.08 pounds VOC per hour for each combustion turbine.

(2) During normal simple cycle operation (sixty (60) percent load or more), the VOC emissions form each combustion turbine, when firing diesel fuel, shall not exceed 0.0363 pounds per MMBtu on a higher heating value basis, which is equivalent to 13.55 pounds VOC per hour for each combustion turbine.

(3) Good combustion practice shall be implemented to minimize VOC emissions.

D.1.9 Best Available Control Technology for Emergency Diesel Fire Pump

Pursuant to 326 IAC 2-2 (PSD Requirement), the source shall comply with the following:

(1) Perform good combustion practices.

(2) The sulfur content of the diesel fuel used by the fire pump shall not exceed 0.05 percent by weight.

(3) The total input of the diesel fuel to the fire pump shall not exceed 5,755 gallons per twelve consecutive month period, rolled on a monthly basis.

D.1.10 40 CFR 60, Subpart GG (Stationary Gas Turbines)

The four (4) natural gas combustion turbines are subject to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines) because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour (10 MMBtu per hour), based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the Permittee shall:

(1) Limit nitrogen oxides emissions from the natural gas turbines to 0.0113% by volume at 15% oxygen on a dry basis, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt-hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) Limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight.

D.1.11 40 CFR Part 60, Subpart Kb (Volatile Organic Storage Vessels)

Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall notify EPA Region 5 and the OAQ within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. Available data on the storage temperature may be used to determine the maximum vapor pressure as determined in 40 CFR Part 60.117b(e)(1)-(3).

D.1.12 Formaldehyde Limitations

Pursuant to 326 IAC 2-1.1-5 (Air Quality Requirements), the formaldehyde emissions form each combustion turbine stack shall not exceed 0.00026 pounds of formaldehyde per MMBtu.

D.1.13 326 IAC 7-1 (Sulfur Dioxide Emission Limitations)

Pursuant to 326 IAC 7-1.1-2, the sulfur dioxide emissions from the eight (8) turbines shall not exceed 0.5 pounds per million Btu for distillate oil combustion.

D.1.14 Preventive Maintenance Plan [326 IAC 1-6-3]

A Preventive Maintenance Plan, in accordance with Section C - Preventive Maintenance Plan, of this permit, is required for each combustion turbine.

Compliance Determination Requirements

D.1.15 Performance Testing

(a) Pursuant to 326 IAC 3-5 the Permittee shall conduct a performance test, not later than one-hundred and eighty days (180) after a facility startup or monitor installation, on the combustion turbine exhaust stack (#1-#8) in order to certify the continuous emission monitoring systems for NO_X and CO.

(b) Within one-hundred and eighty (180) days after initial startup, the Permittee shall perform formaldehyde test for each combustion turbine stack (#1-#8) utilizing methods approved by the Commissioner when operating at 60%, 75%, and 100% load. These tests shall be performed in accordance with Section C – Performance Testing, in order to verify the formaldehyde emission factor as specified in Condition D.1.12.

(c) Within sixty (60) days after initial startup, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall perform NO_X and CO stack tests for each turbine stack (#1-#8) during a startup/shutdown period, utilizing methods as approved by the Commissioner. These tests shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Condition D.1.4.

(d) Within sixty (60) days after achieving maximum production rate, but no later than one-hundred and eighty (180) days after initial startup, the Permittee shall conduct NO_X and SO_2 stack test for each turbine utilizing methods approved by the Commissioner. These tests shall be performed in accordance with 40 CFR 60.335 and Section C – Performance Testing, in order to document compliance with Condition D.1.10.

(e) Within one-hundred eighty (180) after initial startup, the Permittee shall perform PM, PM_{10} (filterable and condensible), and VOC stack tests for each combustion turbine stack (#1-#8) utilizing methods approved by the Commissioner. These test shall be performed in accordance with Section C – Performance Testing, in order to document compliance with Condition D.1.2 and D.1.8.

(f) IDEM, OAQ retain the authority under 326 IAC 2-1-4(f) to require the Permittee to perform additional and future compliance testing as necessary.

D.1.16 326 IAC 7-1 (Sulfur Content Compliance)

(a) Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per MMBtu by:

(1) Fuel sampling and analysis shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion and shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per MMBtu unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(a) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(b) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(2) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the eight (8) combustion turbines, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, or

(3) Upon written notification of a facility owner or operator to the department, CEMs data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

(c) A determination of noncompliance pursuant to either of the methods specified in (1), (2), or (3) above shall be refuted by evidence of compliance pursuant to the other method.

D.1.17 40 CFR Part 60, Subpart GG Compliance Requirements (Stationary Gas Turbines)

Pursuant to 40 CFR Part 60, Subpart GG (Stationary Gas Turbines), the Permittee shall monitor the nitrogen and sulfur content of the natural gas on a monthly basis as follows:

(a) Determine compliance with the nitrogen oxide and sulfur dioxide standards in 40 CFR

60.332 and 60.333(a), per requirements described in 40 CFR 60.335(c);

(b) Determine the sulfur content of the natural gas being fired in the turbine by ASTM Methods D 1072-80, D 3030-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(c) Determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency.

Owners, operators or fuel vendors may develop custom fuel schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These schedules shall be substantiated with data and must be approved by the Administrator before they can be used to comply with the above requirements.

D.1.18 Continuous Emission Monitoring

(a) The owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2, shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5-1(d).

(b) The Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for each combustion turbine stack for NO_X, CO, and O_2 (#1-#8) in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emission monitoring system (CEMS) shall measure NO_X and CO emissions rates in pounds per hour, uncorrected parts per million, and parts per million on a dry volume basis (ppmvd) corrected to 15% O_2. The use of CEMS to measure and record the NO_X and CO hourly limits, is sufficient to demonstrate compliance with the limitations established in the BACT analysis and set forth in the permit. To demonstrate compliance with the NO_X limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a twenty four (24) operating hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the ppmvd corrected to 15% O_2 over a twenty four (24) hour operating period. The source shall maintain records of the ppmvd corrected to 15% O_2 and the pounds per hour.

(2) The Permittee shall determine compliance with Conditions D.1.4 utilizing data from the NO_X, CO, and O_2 CEMS, the fuel flow meter, and Method 19 calculations.

(3) The Permittee shall submit to IDEM, OAQ within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(4) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7.

(c) The Permittee shall follow parametric monitoring requirements for determining SO_2 emissions contained in the “Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units” in lieu of continuous emissions monitors (CEMS)

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units" protocol.

(2) The Permittee shall apply to IDEM for initial certification to use the "Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil Fired Units" protocol, no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

Record Keeping and Reporting Requirements [326 IAC 2-5.1-3(e)(2)] [326 IAC 2-6.1-5(a)(2)]

D.1.19 Record Keeping Requirements

(a) To document compliance with Condition D.1.2, D.1.5 through D.1.8, the Permittee shall maintain records of the following:

(1) Amount of natural gas combusted (in MMCF) per turbine during each month

(2) The percent sulfur content of the natural gas

(3) The percent sulfur content of the diesel fuel

(4) The average heat input, on a higher heating value basis, of each turbine on a 30-day rolling average.

(b) To document compliance with Condition D.1.4, the Permittee shall maintain records of the following:

(1) The type of operation (i.e., startup or shutdown) with supporting operational data

(2) The total number of minutes for startup or shutdown per 24-hour period per turbine

(3) The CEMS data, fuel flow meter data, and Method 19 calculations corresponding to each startup and shutdown period.

(c) To document compliance with Conditions D.1.5 and D.1.6, the Permittee shall maintain records of the emission rates of NO_X and CO in pounds per hour and ppmvd corrected to 15% oxygen.

(d) To document compliance with Condition D.1.18, the Permittee shall maintain records, including raw data of all monitoring data and supporting information, for a minimum of five (5) years from the date as described in 326 IAC 3-5-7(a). The records shall include the information described in 326 IAC 3-5-7(b).

(e) To document compliance with Condition D.1.10, the source shall maintain records of the natural gas analyses, including the sulfur and nitrogen content of the gas, for a period of three (3) years.

(f) To document compliance with Condition D.1.11, the Permittee shall:

(1) Maintain the records of the volatile organic liquid (VOL) stored.

(2) The period of storage.

(3) The maximum true vapor pressure of the volatile organic liquid (VOL) during respective storage period.

(4) Keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel.

(g) To document compliance with Condition D.1.9, the Permittee shall maintain records of the following:

(1) Amount of diesel fuel combusted in the emergency fire pump during each month

(2) The percent sulfur content of the diesel fuel

(h) All records shall be maintained in accordance with Section C – General Record Keeping Requirements, of this permit

D.1.20 Reporting Requirements

The Permittee shall submit the following information on a quarterly basis:

(a) Records of excess NO_X and CO emissions (defined in 326 IAC 3-5-7 and 40 CFR Part 60.7) from the continuous emissions monitoring system. These reports shall be submitted within thirty (30) calendar days following the end of each calendar quarter and in accordance with Section C – General Reporting Requirements of this permit.

(b) The Permittee shall report periods of excess emissions, as required by 40 CFR 60.334(c)

(c) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.2 or 326 IAC 7-4, shall submit to the Commissioner the following reports based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3:

(1) Shall submit reports of the calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per MMBtu upon request.

(d) A quarterly summary of the CEMs data to document compliance with D.1.5 and D.1.6 shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

(e) A quarterly summary of the total number of startup and shutdown hours of operation and emissions corresponding to startup and shutdown to document compliance with Condition D.1.4, shall be submitted to the address listed in Section C – General Reporting Requirements, of this permit, within thirty (30) days after the end of the quarter being reported.

MALFUNCTION REPORT

INDIANA DEPARTMENT OF ENVIRONMENTAL MANAGEMENT
OFFICE OF AIR QUALITY
FAX NUMBER - 317 233-5967

This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

THIS FACILITY MEETS THE APPLICABILITY REQUIREMENTS BECAUSE IT HAS POTENTIAL TO EMIT 25 LBS/HR PARTICULATE MATTER ?_____, 100 LBS/HR VOC ?_____, 100 LBS/HR SULFUR DIOXIDE ?_____ OR 2000 LBS/HR OF ANY OTHER POLLUTANT ?_____ EMISSIONS FROM MALFUNCTIONING CONTROL EQUIPMENT OR PROCESS EQUIPMENT CAUSED EMISSIONS IN EXCESS OF APPLICABLE LIMITATION ________.

THIS MALFUNCTION RESULTED IN A VIOLATION OF: 326 IAC _______ OR, PERMIT CONDITION # _______ AND/OR PERMIT LIMIT OF _______________

THIS INCIDENT MEETS THE DEFINITION OF 'MALFUNCTION' AS LISTED ON REVERSE SIDE ? Y N

THIS MALFUNCTION IS OR WILL BE LONGER THAN THE ONE (1) HOUR REPORTING REQUIREMENT ? Y N

COMPANY:____PHONE NO. ( )________________________
LOCATION: (CITY AND COUNTY)____
PERMIT NO. _________________ AFS PLANT ID: _________________ AFS POINT ID: _________________ INSP.___________
CONTROL/PROCESS DEVICE WHICH MALFUNCTIONED AND REASON:____
____

DATE/TIME MALFUNCTION STARTED: _____/_____/ 20____ ____ AM / PM

ESTIMATED HOURS OF OPERATION WITH MALFUNCTION CONDITION: ____

DATE/TIME CONTROL EQUIPMENT BACK-IN SERVICE______/______/ 20____ _______________ AM/PM

TYPE OF POLLUTANTS EMITTED: TSP, PM-10, SO2, VOC, OTHER:____

ESTIMATED AMOUNT OF POLLUTANT EMITTED DURING MALFUNCTION: ____
____

MEASURES TAKEN TO MINIMIZE EMISSIONS:____
____

REASONS WHY FACILITY CANNOT BE SHUTDOWN DURING REPAIRS:

CONTINUED OPERATION REQUIRED TO PROVIDE ESSENTIAL* SERVICES:______________________________________
CONTINUED OPERATION NECESSARY TO PREVENT INJURY TO PERSONS:______________________________________
CONTINUED OPERATION NECESSARY TO PREVENT SEVERE DAMAGE TO EQUIPMENT:____________________________
INTERIM CONTROL MEASURES: (IF APPLICABLE)____
____
____

MALFUNCTION REPORTED BY:__________________________________TITLE:_____________________________
(SIGNATURE IF FAXED)

MALFUNCTION RECORDED BY:______________________DATE:_________________TIME:_________________

Please note - This form should only be used to report malfunctions applicable to Rule 326 IAC 1-6 and to qualify for the exemption under 326 IAC 1-6-4.

326 IAC 1-6-1 Applicability of rule

Sec. 1. This rule applies to the owner or operator of any facility required to obtain a permit under 326 IAC 2-5.1 or 326 IAC 2-6.1.

326 IAC 1-2-39 "Malfunction" definition

Sec. 39. Any sudden, unavoidable failure of any air pollution control equipment, process, or combustion or process equipment to operate in a normal and usual manner.

***Essential services** are interpreted to mean those operations, such as, the providing of electricity by power plants. Continued operation solely for the economic benefit of the owner or operator shall not be sufficient reason why a facility cannot be shutdown during a control equipment shutdown.

If this item is checked on the front, please explain rationale:

____

____

Indiana Department of Environmental Management
Office of Air Management
Compliance Data Section

Quarterly Report

Company Name: Duke Energy Knox, LLC
Location: Corner of SE1275E and SE300S, Wheatland, Indiana 4759
Permit No.: 083-12674-00043
Source: One (1) emergency diesel fire pump
Limit: 5,755 gallons per twelve (12) consecutive month period

Year: ____________

Month	Diesel Fuel Oil Usage (gallons/month)	Diesel Fuel Oil Usage for previous month(s) (gallons)	Diesel Fuel Oil Usage for twelve month period (gallons)

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ______________________________
Title / Position: ______________________________
Signature: ______________________________
Date: ______________________________
Phone: ______________________________

Indiana Department of Environmental Management
Office of Air Management
Compliance Data Section

Quarterly Report

Company Name: Duke Energy Knox, LLC
Location: Corner of SE1275E and SE300S, Wheatland, Indiana 4759
Permit No.: 083-12674-00043
Source: Eight (8) Combustion Turbines
Limit: 240 startup/shutdown per twelve month period (Startup or shutdown shall not exceed 1 hour)

Month: _________________ **Year:** ______________

Day/Turbine#	1	2	3	4	5	6	7	8	Day/Turbine#	1	2	3	4	5	6	7	8
1									17								
2									18								
3									19								
4									20								
5									21								
6									22								
7									23								
8									24								
9									25								
10									26								
11									27								
12									28								
13									29								
14									30								
15									31								
16									no. of deviations								

9 No deviation occurred in this quarter.

9 Deviation/s occurred in this quarter.
Deviation has been reported on:

Submitted by: ____
Title / Position: ____
Signature: ____
Date: ____
Phone: ____

Mail to: Permit Administration & Development Section
Office of Air Quality
100 North Senate Avenue
P. O. Box 6015
Indianapolis, Indiana 46206-6015

Duke Energy Knox, LLC
5400 Westheimer Court
Houston, Texas 77056-5310

Affidavit of Construction

I, ____, being duly sworn upon my oath, depose and say:
(Name of the Authorized Representative)

1. I live in ______________________________ County, Indiana and being of sound mind and over twenty-one (21) years of age, I am competent to give this affidavit.

2. I hold the position of ______________________ for ________________________.
(Title) (Company Name)

3. By virtue of my position with __________________________________,I have personal
(Company Name)
knowledge of the representations contained in this affidavit and am authorized to make these representations on behalf of ____ .
(Company Name)

4. I hereby certify that Duke Energy Knox LLC, SE 1275 E and SE 300 S, Wheatland, Indiana, 47597, completed construction of the simple cycle merchant electric generating plant on ____________________in conformity with the requirements and intent of the construction permit application received by the Office of Air Quality on September 5, 2000 and as permitted pursuant to **Construction Permit No. CP-083-12674, Plant ID No. 083-00043** issued on ______.

5. I hereby certify that Duke Energy Knox LLC is now subject to the Title V program and will submit a Title V operating permit application within twelve (12) months from the postmarked submission date of this Affidavit of Construction.

Further Affiant said not.
I affirm under penalties of perjury that the representations contained in this affidavit are true, to the best of my information and belief.

Signature

Date

STATE OF INDIANA)
)SS

COUNTY OF ____________________)

Subscribed and sworn to me, a notary public in and for __________________________ County and State of Indiana on this ____________________ day of ______________________, 20 _________ .

My Commission expires:

Signature

Name (typed or printed)

Indiana Department of Environmental Management
Office of Air Quality

Addendum to the Technical Support Document (TSD) for New Construction and P.S.D. Operation

Source Background and Description

Source Name: Duke Energy Knox, LLC
Source Location: Corner of SE1275E and SE300S, Wheatland, Indiana 47597
County: Knox
Construction Permit No.: CP-083-12674-00043
SIC Code: 4911
Permit Reviewer: David Howard

On April 5, 2001, the Office of Air Quality (OAQ) had a notice published in the *Sun Commercial*, Vincennes, Indiana, stating that Duke Energy Knox, LLC had a applied for a Prevention of Significant Deterioration (PSD) permit for the construction of a 640 megawatt (MW) simple cycle merchant electric generating station consisting of eight combustion turbine generators with a nominal heat input rate of 1,158 MMBtu per hour. The detailed description of equipment can be found in the Prevention of Significant Deterioration construction permit.

The notice also stated that OAQ proposed to issue a permit for this installation and provided information on how the public could review the proposed permit and other documentation. Finally, the noticed informed interested parties that there was a period of thirty (30) days to provide comments on whether or not this permit should be issued as proposed.

The IDEM, OAQ has made the following clarifications, additions or changes to the proposed construction permit (changes are bolded for emphasis):

(1) The following typographical error has be changed in Condition D.1.5:

D.1.5 Nitrogen Oxides (NO_X) Emission Limitations

(a) Pursuant to 326 IAC 2-2 (PSD Requirements) each combustion turbine generating unit shall comply with the following, excluding startup and shutdown emissions:

(1) Use dry low-NO_X combustors in conjunction with natural gas.

(2) Use water injection in conjunction with diesel fuel.

(3) During normal simple cycle operation (sixty (60) percent load or more), the NO_X emissions from each combustion turbine when burning natural gas shall not exceed 9.0 ppmvd corrected to fifteen (15) percent oxygen, based on a twenty four (24) operating hour averaging period, which is equivalent to 31.96 pounds per hour for each combustion turbine.

(4) During normal simple cycle operation (sixty (60) percent load or more), the NO_X emissions from each combustion turbine when burning ~~natural gas~~ **diesel fuel** shall not exceed 42 ppmvd corrected to fifteen (15) percent oxygen, based on one (1) averaging period, which is equivalent to 166.98 pounds per hour for each combustion turbine.

(b) Pursuant to 326 IAC 2-2 (PSD Requirements), the combined annual NO_X emissions from each of the eight (8) combustion turbines when burning natural gas and diesel fuel, shall not exceed 73.71 tons per year. However, each of the eight combustion turbines shall not exceed 41.75 tons per year of NO_X when firing only diesel fuel.

On May 9, 2001 a public hearing was held for the Duke Energy Knox Generating Station's Prevention of Significant Deterioration permit and Acid Rain Deposition Control Program permit. Mr. Ron Clark presented the following comment:

Comment 1: What effects of acid rain will I see as a result of this proposed plant at my property?

Response 1: The 1990 Clean Air Act created what is entitled the acid rain deposition control program. The purpose of this program was to dramatically reduce the emissions of the pollutants that cause acid rain and to reduce the effects of acid rain. Currently, emissions of sulfur dioxide, for instance, have been reduced by ten million tons across the United States. The second phase of the acid rain program affected the emissions of nitrogen oxides. There are no provisions of this program that apply to this plant. However, with respect to SO_2 there is essentially a nationwide cap that emissions cannot increase above, so, even when a new plant is permitted the program is set up to be a market-based program that relies on trading. Therefore, the plant has to purchase SO_2 emission credits in order to operate. The Clean Air Act addresses the national problem by greatly reducing SO_2 emissions across the country. The program was not set up to look at any local effects that an individual plant would have on the area, but if emissions are reduced by a very large amount across the country, then the impact of acid rain overall would be diminished. The following list provides a highlight of various places to obtain information on acid rain.

http://www.epa.gov/airmarkets/acidrain/
http://www.epa.gov/airmarkets/progress/arpreport/acidrainprogress.pdf
http://nadp.sws.uiuc.edu/default.html

In addition, the Prevention of Significant Deterioration (PSD) program requires that an air modeling impact analysis be conducted to determine if there will be any violation of the National Ambient Air Quality Standards (NAAQS). The Office of Air Quality utilizes a computer model, which is approved by EPA, to predict what the impact of the emissions from the proposed plant will have on the surrounding area, and compares them to the standards that are established to predict public health.

Section 109(a) of the Clean Air Acts (CAA) directs the U.S. EPA to purpose and promulgate primary and secondary NAAQS for the six criteria pollutants. The six criteria pollutants are carbon monoxide, sulfur dioxide, nitrogen dioxide, ozone, lead and particulate matter. Primary air quality standards define the air quality required to prevent any adverse impact on human health with an adequate margin of safety built in. Secondary standards are established to prevent adverse effects on vegetation, property, visibility, materials and other elements of the environment. Table 1 shows the current ambient air quality standards that EPA has promulgated.

Table 1

Pollutant	Averaging Period	NAAQS Standard Primary	(ug/m3) Secondary
Particulate Matter less than 10 micrometers/ microns (PM10)	Annual 24 hour	50 150	None None
Sulfur Dioxide (SO2)	Annual 24 Hour 3 Hour	80 365 None	None None 1300

Nitrogen Dioxide (NO2)	Annual	100	Same as primary
Ozone (O3)	1 Hour	120ppb	Same as primary
Carbon Dioxide (CO)	8 hour 1 hour	10000 40000	Same as primary Same as primary
Lead (Pb)	Calendar Quarter	1.5	Same as primary

Significant impact levels are well below primary and secondary standards and are used as triggers to determine whether a full impact analysis is necessary. The OAQ analysis is shown in Table 2 and provided the following concentrations for Duke Energy, Knox County.

Table 2

Pollutant	**Year**	**Time-Averaging Period**	**Maximum Modeled Impacts**	**Significant Impact Levels**	**Refined Analysis Required**
CO	1987	1-hour	895.27	**2000.0**	No
CO	1989	8-hour	51.50	**500.0**	No
NO_2	1987	Annual	0.67	**1.0**	No
SO_2	1990	3-hour	13.69	**25.0**	No
SO_2	1989	24-hour	1.92	**5.0**	No
SO_2	1991	Annual	0.01	**1.0**	No
PM_{10}	1990	24-hour	1.74	**5.0**	No
PM_{10}	1987	Annual	0.04	**1.0**	No

As indicated in the above tables, the modeled concentrations are below the significant impact levels, and are below primary and secondary standards set forth by U. S. EPA.

Indiana Department of Environmental Management
Office of Air Quality

Technical Support Document (TSD) for New Construction and P.S.D. Operation

Source Background and Description

Source Name: Duke Energy Knox, LLC
Source Location: Corner of SE1275E and SE300S, Wheatland, Indiana 47597
County: Knox
Construction Permit No.: CP-083-12674-00043
SIC Code: 4911
Permit Reviewer: David Howard

The Office of Air Quality (OAQ) has reviewed an application from Knox Generating Station relating to the construction and operation of a 640 MW simple cycle merchant electric generating plant. The source will fire natural gas and low-sulfur diesel fuel as a backup fuel. The source consists of the following equipment:

New Emission Units and Pollution Control Equipment

(a) Eight (8) General Electric 7EA simple cycle, natural gas-fired combustion turbine generators, designated as units CTG1-CTG8, with a maximum heat input capacity of 1158 MMBtu/hr each and a nominal output of 80 MW each, exhausting to stacks designated as #1-#8. The nitrogen oxide emissions are controlled by dry low-NO_X combustors.

(b) One (1) emergency diesel fire pump, designated as unit #9, with a maximum heat input capacity of 1.6 MMBtu/hr and exhausts to a stack designated as #9.

(c) Four (4) diesel fuel storage tanks, designated as tans #1-#4, with a maximum capacity of 520,000 gallons per tank, a maximum of 84,650 ft^3 per tank.

Stack Summary

Stack ID	Operation	Height (feet)	Diameter (feet)	Flow Rate (acfm)	Temperature (^0F)
1-8	Eight (8) turbines	92	15	1,676,315	1100
9	Diesel fire pump	4	0.420	1,718	985

Recommendation

The staff recommends to the Commissioner that the construction and operation be approved. This recommendation is based on the following preliminary facts and conditions:
Information, unless otherwise stated, used in this review was derived from the application and additional information submitted by the applicant.

An application for the purposes of this preliminary review was received on September 5, 2000, with additional information received on December 18, 2000, March 5, 2001, and March 6, 2001.

Emissions Calculations

See Appendix A (Emissions Calculation Spreadsheets for detailed calculations (six (6) pages)). Criteria pollutant emission rates from the turbines are based on General Electric vendor data

Hazardous Air Pollutants (HAPs) emission calculations are based on the USEPA 's AP-42 (Section 3.1 Stationary Gas Turbines, final 4/2000) emission factors. An alternative emission factor for formaldehyde was submitted by source. The permit will require a formaldehyde stack test to verify the proposed formaldehyde emission factor.

The turbine's startup and shutdown emissions are based on a maximum of 240 startup and shutdown cycles per year per turbine.

Based on the periods when this project will typically be operated (summer months), the Office of Air Quality determined that the criteria pollutant emission rates should be based on a realistic operating scenario. Peaking operations tend to operate during extreme weather periods, mainly in the hotter summer months. Based on vendor information supplied by the source, the NO_X emission rates tend to increase with a decrease in temperature. The OAQ concluded that basing emission rates for all criteria pollutants, in pounds per hour, off of a worst case site temperature and operating load, would yield higher emissions than during the period of time when the turbines would typically be operating. Therefore, the emission rates, in pounds per hour, based on the average site temperature of 53 ^{o}F are used in the calculations. Compliance with the NO_X and CO emissions shall be demonstrated by the use of continuous emissions monitoring systems.

Potential To Emit

Pursuant to 326 IAC 2-1.1-1(16), Potential to Emit is defined as "the maximum capacity of a stationary source or emissions unit to emit any air pollutant under its physical and operational design. Any physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and restrictions on hours of operation or type or amount of material combusted, stored, or processed shall be treated as part of its design if the limitation is enforceable by the U. S. EPA, the department, or the appropriate local air pollution control agency."

The following PTE table is based on worst case emission rates of the turbines and fire pump and 8,760 hours of operation per year. The NOx PTE of the turbines is based on an annual worst-case emission rate of 9 ppmvd (equivalent to 31.8 pounds per hour) as per Appendix A, Supporting Emission Rate Calculations.

Pollutant	Potential To Emit (tons/year)
Particulate Matter (PM)	876.53
Particulate Matter (PM10)	876.53
Sulfur Dioxide (SO_2)	1472.93
Volatile Organic Compounds (VOC)	474.84
Carbon Monoxide (CO)	1915.97
Nitrogen Oxides (NO_x)	5867.92
Single HAP (Manganese)	32.06
Combined HAPs	74.34

(a) The potential to emit (as defined in 326 IAC 2-7-1(29)) of PM_{10}, NO_x, CO and SO_2 are equal to or greater than 100 tons per year. Therefore, the source is subject to the provisions of 326 IAC 2-7.

(b) This new source is a major stationary source because at least one regulated attainment pollutant is emitted at a rate of 250 tons per year or greater. This new source is not one of the 28 listed source categories. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

County Attainment Status

The source is located in Knox County.

Pollutant	Status
PM-10	Attainment
SO_2	Attainment
NO_2	Attainment
Ozone	Attainment
CO	Attainment
Lead	Attainment

(a) Volatile organic compounds (VOC) and oxides of nitrogen (NOx) are precursors for the formation of ozone. Therefore, VOC emissions are considered when evaluating the rule applicability relating to the ozone standards. Knox County has been designated as attainment or unclassifiable for ozone. Therefore, VOC and NOx emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

(b) Knox County has been classified as attainment or unclassifiable for SO_2, PM_{10} and CO. Therefore, these emissions were reviewed pursuant to the requirements for Prevention of Significant Deterioration (PSD), 326 IAC 2-2 and 40 CFR 52.21.

Source Status

New Source PSD Definition (emissions after controls, based on 8,760 hours of operation per year at rated capacity **and/ or** as otherwise limited). The limited potential to emit for NO_X is based on the worst case scenario, which is firing natural gas for 2,000 hours per year and diesel fuel for 500 hours per year. The limited potential to emit for CO is based on the worst case scenario, which is firing natural gas 2,500 hours per year. This will allow the source the flexibility to fire any combination of natural gas and diesel fuel up to total operation of 2,500 hours per year, with diesel fuel firing not to exceed 500 hours per year.

Pollutant	Emissions (ton/yr)
PM	138.12
PM10	138.12
SO_2	132.26
VOC	43.87
CO	659.30

NO_x	625.42
Single HAP (Formaldehyde)	3.07
Combined HAPs	8.02

(a) This new source is a major stationary source because at least one regulated attainment pollutant is emitted at a rate of 250 tons per year or greater. This new source is not one of the 28 listed source categories. Therefore, pursuant to 326 IAC 2-2, and 40 CFR 52.21, the PSD requirements apply.

Part 70 Permit Determination

326 IAC 2-7 (Part 70 Permit Program)

This new source is subject to the Part 70 Permit requirements because the potential to emit (PTE) of:

(a) at least one of the criteria pollutant is greater than or equal to 100 tons per year

(b) a single hazardous air pollutant (HAP) is greater than or equal to 10 tons per year, or

(c) any combination of HAPs is greater than or equal to 25 tons/year.

This new source shall apply for a Part 70 (Title V) operating permit within twelve (12) months after this source becomes subject to Title V.

Federal Rule Applicability

40 CFR 60, Subpart GG (Stationary Gas Turbines):

The eight (8) combustion turbines are subject to 40 CFR Part 60, Subpart GG because the heat input at peak load is equal to or greater than 10.7 gigajoules per hour, based on the lower heating value of the fuel fired.

Pursuant to 326 IAC 12-1 and 40 CFR 60, Subpart GG (Stationary Gas Turbines), the owner or operator shall:

(1) Limit nitrogen oxides emissions, as required by 40 CFR 60.332, to:

$$STD = 0.0075 \frac{(14.4)}{Y} + F,$$

where STD = allowable NO_x emissions (percent by volume at 15 percent oxygen on a dry basis).

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour.

F = NO_x emission allowance for fuel-bound nitrogen as defined in paragraph (a)(3) of 40 CFR 60.332.

(2) limit sulfur dioxide emissions, as required by 40 CFR 60.333, to 0.015 percent by volume at 15 percent oxygen on a dry basis, or use natural gas fuel with a sulfur content less than or equal to 0.8 percent by weight;

(3) determine compliance with the nitrogen oxides and sulfur dioxide standards in 40 CFR 60.332 and 60.333(a), per the requirements described in 40 CFR 60.335(c);

(4) determine the sulfur content of the natural gas being fired in the turbine by ASTM methods D 1072-80, D 3031-81, D 4084-82, or D 3246-81. The applicable ranges of some ASTM methods mentioned are not adequate to measure the levels of sulfur in some fuel gases. Dilution of samples before analysis (with verification of the dilution ratio) may be used, subject to the approval of the Administrator; and

(5) determine the nitrogen content of the natural gas being fired in the turbine by using analytical methods and procedures that are accurate to within 5 percent and are approved by the Administrator.

(6) report periods of excess emissions, as required by 40 CFR 334(c).

The analyses required above may be performed by the owner or operator, a service contractor retained by the owner or operator, the fuel vendor or any other qualified agency

Owners, operators or fuel vendors may develop custom schedules for determination of the nitrogen and sulfur content based on the design and operation of the affected facility and the characteristics of the fuel supply. These custom schedules shall be substantiated with data and must be approved by the Administrator and IDEM before they can be used to comply with the above requirements.

40 CFR Part 60, Subpart Kb (Volatile Organic Storage Vessels)

Tanks #1-#4 are subject to 40 CFR Part 60, Subpart Kb because the maximum capacity of each is greater than 40 m^3 that is used to store volatile organic liquids (including petroleum) for which construction, reconstruction, or modification commenced after July 23, 1984.

The tanks are exempt from the General Provisions (Part 60, subpart A) and from the provisions of this subpart because the tanks have a capacity greater than or equal to 151 m^3, storing liquid with a maximum true vapor pressure less than 3.5 kPa.

Pursuant to 40 CFR Part 60, Subpart Kb, the Permittee shall:

(1) maintain the records of the volatile organic liquid (VOL) stored;

(2) the period of storage;

(3) the maximum true vapor pressure of the volatile organic liquid (VOL) during the respective storage period;

(4) shall keep readily accessible records showing the dimension of the storage vessel and an analysis showing the capacity of the storage vessel;

(5) shall notify the Administrator within 30 days when the maximum true vapor pressure of the liquid exceeds the respective maximum true vapor pressure values for each volume range. (Available data on the storage temperature may be used to determine the maximum vapor pressure as determined in 40 CFR Part 60.117b(e)(1)-(3))

40 CFR Part 63 (National Emission Standards for Hazardous Air Pollutants)

There are currently no National Emission Standards for Hazardous Air Pollutants (NESHAPs) applicable to this source

40 CFR Part 72-80 (Acid Rain Program)

The requirements of this program shall be detailed in the Acid Rain, Phase II Permit.

State Rule Applicability

326 IAC 1-5-2 and 326 IAC 1-5-3 (Emergency Reduction Plans):

Pursuant to 326 IAC 1-5-2 (Emergency Reduction Plans; Submission):

(a) The Permittee shall prepare written emergency reduction plans (ERPs) consistent with safe operating procedures.

(b) These ERPs shall be submitted for approval to:

Indiana Department of Environmental Management
Compliance Branch, Office of Air Quality
100 North Senate Avenue, P.O. Box 6015
Indianapolis, Indiana 46206-6015
within 180 days from the date on which this source commences operation.

(c) If the ERP is disapproved by IDEM, OAQ, the Permittee shall have an additional thirty (30) days to resolve the differences and submit an approvable ERP. If after this time, the Permittee does not submit an approvable ERP, then IDEM, OAQ, shall supply such a plan.

(d) These ERPs shall state those actions that will be taken, when each episode level is declared, to reduce or eliminate emissions of the appropriate air pollutants.

(e) Said ERPs shall also identify the sources of air pollutants, the approximate amount of reduction of the pollutants, and a brief description of the manner in which the reduction will be achieved.

(f) Upon direct notification by IDEM, OAQ, that a specific air pollution episode level is in effect, the Permittee shall immediately put into effect the actions stipulated in the approved ERP for the appropriate episode level. [326 IAC 1-5-3]

The source is subject to 326 IAC 1-5-2 and 1-5-3 because the source’s CO, NOx, SO_2 and PM_{10} PTE is greater than 100 tons per year.

326 IAC 1-6-3 (Preventive Maintenance):

(a) The Permittee shall prepare and maintain Preventive Maintenance Plans (PMP) within ninety (90) days after commencement of operation, including the following information on each:

(1) Identification of the individual(s) responsible for inspecting, maintaining, and repairing emission units;

(2) A description of the items or conditions that will be inspected and the inspection schedule for said items or conditions;

(3) Identification and quantification of the replacement parts that will be maintained in inventory for quick replacement.

(b) The Permittee shall implement the Preventive Maintenance Plans as necessary to ensure that lack of proper maintenance does not cause or contribute to a violation of any limitation on emissions or potential to emit.

(c) PMP’s shall be submitted to IDEM and OAQ upon request and shall be subject to review and approval by IDEM and OAQ.

326 IAC 1-7 (Stack Height Provisions):

Stacks designated as #1-#8 are subject to the requirements of 326 IAC 1-7 (Stack Height Provisions) because the potential emissions, which exhaust through the above mentioned stacks, are greater than 25 tons per year of PM and SO_2. This rule requires that the stack be constructed using Good Engineering Practice (GEP), unless field studies or other methods of modeling show to the satisfaction of IDEM that no excessive ground level concentrations, due to less than adequate stack height, will result.

326 IAC 2-4.1-1 (New Source Toxics Rule)

The New Source Toxics Control rule requires any new or reconstructed major source of hazardous air pollutants (HAPs) for which there are no applicable NESHAP to implement maximum achievable control technology (MACT), determined on a case-by-case basis, when the potential to emit is greater than 10 tons per year of any single HAP. Information on emissions of the 187 hazardous air pollutants are listed in the OAQ Construction Permit Application, Form Y (set forth in the Clean Air Act Amendments of 1990). These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industry.

The New Source Toxic Rule is not applicable because any single HAP emission is not greater than or equal to 10 tons per year and any combination HAP emissions are not greater than or equal to 25 tons per year.

326 IAC 2-2 (Prevention of Significant Deterioration):

This new source is subject to the requirements of 326 IAC 2-2 (Prevention of Significant Deterioration) for emissions of PM, PM_{10}, SO_2, CO, NO_X because the potential to emit for these pollutants exceed the PSD major “significant” thresholds, as specified in 326 IAC 2-2-1. Therefore, the PSD provisions require that this new source be reviewed to ensure compliance with the National Ambient Air Quality Standard (NAAQS), the applicable PSD air quality increments, and the requirements to apply the Best Available Control Technology (BACT) for the affected pollutants.

The attached modeling analysis, included in Appendix B, was conducted to show that the major new source does not violate the NAAQS and does not exceed the incremental consumption above eighty percent (80%) of the PSD increment for any affected pollutant.

The BACT Analysis Report, included in Appendix C, was conducted for the major source PSD pollutants for each process on a case-by-case basis by reviewing similar process controls and new available technologies. The BACT determination is based on the cost per ton of pollutant removed, energy requirements, and environmental impacts. The following BACT emission limitations apply to the proposed source:

Simple Cycle Operation

Pollutant	Combustion Turbines Firing Natural Gas	Limit	Combustion Turbines Firing Diesel Fuel	Limit	Startup/Shutdown	Limit (lb/startup and shutdown
NO_X	Dry Low-NOx Combustors	9.0 ppmvd @ 15% O_2 (24-hr operating average)	Water Injection	42 ppmvd @ 15% O_2 (1-hr average)	Limited to 1 hour per startup/shutdown	NG (20.7/11) Diesel (31.6/17.5)
CO	Good Combustor Design	25 ppmvd @ 15% O_2 (24-hr average)	Good Combustor Design	25 ppmvd @ 15% O_2 (1-hr average)	Limited to 1 hour per startup/shutdown	NG (65.5/58.9) Diesel (76.4/65.5)

VOC	Good Combustion Control, and Limited Hours of Operation	2.08 lb/hr	Good Combustion Control, and Limited Hours of Operation	13.55 lb/hr	N/A	N/A
SO_2	Natural Gas as Sole Fuel, and Limited Hours of Operation	6.02 lb/hr	Low Sulfur Diesel Fuel, and Limited Hours of Operation	42.04 lb/hr	N/A	N/A
PM/PM_{10}	Natural Gas as Sole Fuel, and Limited Hours of Operation	11.0 lb/hr	Limited Hours of Operation	25.01 lb/hr	N/A	N/A
Opacity		20%		20%	N/A	N/A

326 IAC 2-6 (Emission Reporting):

This facility is subject to 326 IAC 2-6 (Emission Reporting), because the source will emit more than 100 tons/year of NOx and CO. Pursuant to this rule, the owner/operator of this facility must annually submit an emission statement of the facility. The annual statement must be received by July 1 of each year and must contain the minimum requirements as specified in 326 IAC 2-6-4.

326 IAC 3-5 (Continuous Monitoring of Emissions):

(a) Pursuant to 326 IAC 3-5-1(d)(1), the owner or operator of a new source with an emission limitation or permit requirement established under 326 IAC 2-5.1-3 and 326 IAC 2-2 shall be required to install a continuous emissions monitoring system or alternative monitoring plan as allowed under the Clean Air Act and 326 IAC 3-5.

(b) For NOx and CO, the Permittee shall install, calibrate, certify, operate and maintain a continuous emissions monitoring system for stacks designated as #1-#8 in accordance with 326 IAC 3-5-2 and 3-5-3.

(1) The continuous emissions monitoring system (CEMS) shall measure NO_x and CO emissions rates in pounds per hour and parts per million (ppmvd) at 15% O_2. The use of CEMS to measure and record the NOx and CO hourly emission rates is sufficient to demonstrate compliance with the limits established in the BACT analyses. To demonstrate compliance with the NOx limit, the source shall take an average of the parts per million (ppmvd) corrected to 15 percent O_2 over a twenty-four (24) operating hour averaging period. To demonstrate compliance with the CO limit, the source shall take an average of the parts per million (ppmvd) corrected to 15 percent O_2 over a twenty four (24) hour operating averaging period. The source shall maintain records of the parts per million and the pounds per hour.

(2) The Permittee shall submit to IDEM, OAQ, within ninety (90) days after monitor installation, a complete written continuous monitoring standard operating procedure (SOP), in accordance with the requirements of 326 IAC 3-5-4.

(3) The Permittee shall record the output of the system and shall perform the required record keeping, pursuant to 326 IAC 3-5-6, and reporting, pursuant to 326 IAC 3-5-7. The source shall also be required to maintain records of the amount of natural gas combusted per turbine on a monthly basis.

(4) In instances of downtime, the source shall use vendor provided emission factors for stationary gas turbines, to demonstrate compliance with the CO limit established under Condition D.1.4, and use the Missing Data Substitution Procedures outlined in 40 CFR Part 75, Subpart D to demonstrate compliance with the NOx limit, established under Condition D.1.2.

(5) The source may submit to the OAQ alternative emission factors based on the source's CEMS data (collected over one (1) season of operation; where a season is defined as the period of time from May 1 through September 30) and the corresponding site temperatures, to use in lieu of the vendor provided emission factors in instances of downtime. The alternative emissions factors must be approved by the OAQ prior to use in calculating emissions for the limitations established in this permit. The alternative emission factors shall be based upon collected monitoring and test data supplied from an approved continuous emissions monitoring system. In the event that the information submitted does not contain sufficient data to establish appropriate emission factors, the source shall continue to collect data until appropriate emission factors can be established. During this period of time, the source shall continue to use AP-42 emission factors for CO compliance determination and use the NOx Missing Data Substitution Procedures specified in 40 CFR Part 75, Subpart D for NOx compliance determination, in periods of downtime.

(c) The Permittee shall follow parametric monitoring requirements for determining SO_2 emissions contained in the "*Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units*" in lieu of continuous emissions monitoring system (CEMS).

(1) Pursuant to the procedures contained in 40 CFR 75.20, the Permittee shall complete all testing requirements to certify the use of the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* protocol.

(2) The Permittee shall apply to IDEM for initial certification to use the *"Optional SO_2 Emissions Data Protocol for Gas-Fired and Oil-Fired Units"* protocol, no later than 45 days after the compliance of all certification tests.

(3) All certification and compliance methods shall be conducted in accordance with the procedures outlined in 40 CFR Part 75, Appendix D.

(4) The source shall maintain records of the sulfur content of the pipeline natural gas, the amount gas combusted per turbine on a monthly basis, and the heat input capacity.

Compliance with this condition shall determine continuous compliance with the NO_X, CO and SO_2 emission limits established under the preliminary PSD BACT (326 IAC 2-2).

326 IAC 5-1 (Opacity Limitations)

Opacity limitations established under 326 IAC 2-2 (PSD Requirements) satisfies limitations required by 326 IAC 5-1 (Opacity Limitations).

326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating)

This new source is not subject to the requirements of 326 IAC 6-2 (Particulate Emission Limitations for Sources of Indirect Heating) because the combustion turbines units are not utilized for indirect heating.

326 IAC 6-4 (Fugitive Dust Emissions)

Pursuant to 326 IAC 6-4 (Fugitive Dust Emissions), the Permittee shall be in violation of 326 IAC 6-4 (Fugitive Dust Emissions) if any of the criteria specified in 326 IAC 6-4-2(1) though (4) are violated. Observations of visible emissions crossing the property line of the source at or near ground level must be made by a qualified representative of IDEM. [326 IAC 6-4-5(c)]. The proposed electric generating plant is subject to the requirements of 326 IAC 6-4 because this rule applies to all sources of fugitive dust. Pursuant to the applicability requirements (326 IAC 6-2-1(d) and (e)), "fugitive dust" means the generation of particulate matter to the extent that some portion of the material escapes beyond the property line or boundaries of the property, right-of-way, or easement on which the source is located. The source shall be considered in violation of this rule if any of the criteria presented in 326 IAC 6-4-2 are violated.

326 IAC 6-5 (Fugitive Particulate Matter Emission Limitations)

The proposed electric generating plant is subject to the requirements of 326 IAC 6-5 because the proposed new plant must obtain a permit pursuant to 326 IAC 2. However, the OAQ shall exempt the source from the fugitive control plan pursuant to 326 IAC 6-5-3(b) because the proposed plant will not have material delivery or handling systems that would generate fugitive emissions and all the roads and parking areas will be paved.

326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations)

Pursuant to 326 IAC 7-1.1-1 (Sulfur Dioxide Emission Limitations) the sulfur dioxide emissions from the eight (8) combustion turbines and the fire pump shall be limited to 0.5 pounds per million Btu for distillate oil combustion.

326 IAC 7-2-1 (Compliance and Reporting Requirements):

(a) Pursuant to 326 IAC 7-2-1, owners or operators of sources or facilities subject to 326 IAC 7-1.2 or 326 IAC 7-4, shall submit to the Commissioner the following reports based on fuel sampling and analysis data in accordance with procedures specified under 326 IAC 3-3:

(1) Shall submit reports of calendar month average sulfur content, heat content, fuel consumption, and sulfur dioxide emission rate in pounds per million Btus upon request.

(b) Pursuant to 326 IAC 7-2-1, the Permittee shall demonstrate that the fuel oil sulfur content does not exceed 0.5 pounds per million Btu by:

(1) Fuel sampling and analysis data shall be collected pursuant to procedures specified in 326 IAC 3-7-4 for oil combustion and shall be determined by using a calendar month average sulfur dioxide emission rate in pounds per million Btus unless a shorter averaging time or alternate methodology is specified under 326 IAC 7-2. Analyzing the oil sample to determine the sulfur content of the oil via the procedures in 40 CFR 60, Appendix A, Method 19.

(A) Oil samples may be collected from the fuel tank immediately after the fuel tank is filled and before any oil is combusted; and

(B) If a partially empty fuel tank is refilled, a new sample and analysis would be required upon filling; or

(2) Compliance may also be determined by conducting a stack test for sulfur dioxide emissions from the three (3) combustion turbines, using 40 CFR 60, Appendix A, Method 6 in accordance with the procedures in 326 IAC 3-6, or

(3) Upon written notification of a facility owner or operator to the department, continuous emission monitoring data collected and reported pursuant to 326 IAC 3-5 may be used as the means for determining compliance.

A determination of noncompliance pursuant to either of the methods specified in (1), (2) or (3) above shall not be refuted by evidence of compliance pursuant to the other method.

326 IAC 8-1-6 (New facilities; General Reduction Requirements):

Pursuant to 326 IAC 8-1-6 (New facilities; general reduction requirements), the requirements of BACT do not apply because the potential to emit of VOC of each turbine and the fire pump is less than 25 tons per year per unit.

326 IAC 9 (Carbon Monoxide Emission Limits):

Pursuant to 326 IAC 9 (Carbon Monoxide Emission Limits), the source is subject to this rule because it is a stationary source which emits CO emissions and commenced operation after March 21, 1972. Under this rule, there is not a specific emission limit because the source is not an operation listed under 326 IAC 9-1-2.

326 IAC 10 (Nitrogen Oxides)

This new source is not subject to the requirements of 326 IAC 10 (Nitrogen Oxides) because the source is not located in the specified counties (Clark and Floyd) listed under 326 IAC 10-1-1.

Air Toxic Emissions

Indiana presently requests applicants to provide information on emissions of the 189 hazardous air pollutants set out in the Clean Air Act Amendments of 1990. These pollutants are either carcinogenic or otherwise considered toxic and are commonly used by industries. They are listed as air toxics on the Office of Air Quality (OAQ) Construction Permit Application Form Y.

(a) This new source will emit levels of air toxics less than those which constitute a major source according to Section 112 of the 1990 Amendments to Clean Air Act.

(b) See attached spreadsheets for detailed air toxic calculations (pages 1-4).

Conclusion

The construction of this electric generating plant will be subject to the conditions of the attached proposed **Construction Permit No. CP-083-12674-00043.**

Appendix A: Emission Calculations

Company Name:	Knox Generating Station
Address:	Corner of SE1275E and SE300S, Wheatland, Indiana 47597
Construction Permit No.:	083-12674-00043
Permit Reviewer:	David Howard

Summary

PTE (tpy)				
Pollutant	Combustion Turbines	Startup/Shutdown	Diesel Fire Pump	Total
NOx	5851.11	34.61	1.163	5886.88
CO	1890.86	123.62	0.251	2014.73
VOC	474.74	N/A	0.093	474.84
SO2	1472.92	N/A	0.014	1472.93
PM/PM10	876.45	N/A	0.083	876.53
Manganese	32.06	N/A	N/A	32.06
Combined HAP	74.34	N/A	N/A	74.34

Limited PTE (tpy)				
Pollutant	Combustion Turbines	Startup/Shutdown	Diesel Fire Pump	Total
NOx	589.65	34.61	1.163	625.42
CO	517.63	123.62	0.251	641.50
VOC	43.77	N/A	0.093	43.87
SO2	132.24	N/A	0.014	132.26
PM/PM10	138.03	N/A	0.083	138.12
Formaldehyde	3.07	N/A	N/A	3.07
Combined HAP	8.02	N/A	N/A	8.02

Combustion Turbine Potential to Emit Calculations - Before Controls or Federally Enforceable Limits

Combustion Turbine Heat input @ 60 F **1158.00** MMBtu/hr Number of Turbines **8**

	Normal Operation	Startup/Shutdown
Hours per year of Operation-Natural Gas	**2000**	**292**
Hours per year of Operation-Distillate Oil	**500**	

Combustion Turbine - Natural Gas					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1158 MMBtu/hr	0.0276 lb/MMBtu	31.96	139.99 tons/yr	1119.91 tons/yr
CO	1158 MMBtu/hr	0.0466 lb/MMBtu	53.96	236.36 tons/yr	1890.86 tons/yr
VOC	1158 MMBtu/hr	0.0018 lb/MMBtu	2.08	9.13 tons/yr	73.04 tons/yr
SO_2	1158 MMBtu/hr	0.0052 lb/MMBtu	6.02	26.37 tons/yr	211.00 tons/yr
PM_{10}	1158 MMBtu/hr	0.0095 lb/MMBtu	11.00	48.18 tons/yr	385.48 tons/yr

Combustion Turbine - Distillate Oil					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NO_X	1158 MMBtu/hr	0.1442 lb/MMBtu	166.98	731.39 tons/yr	5851.11 tons/yr
CO	1158 MMBtu/hr	0.0371 lb/MMBtu	42.96	188.17 tons/yr	1505.38 tons/yr
VOC	1158 MMBtu/hr	0.0117 lb/MMBtu	13.55	59.34 tons/yr	474.74 tons/yr
SO_2	1158 MMBtu/hr	0.0363 lb/MMBtu	42.04	184.12 tons/yr	1472.92 tons/yr
PM_{10}	1158 MMBtu/hr	0.0216 lb/MMBtu	25.01	109.56 tons/yr	876.45 tons/yr

Pollutant	Emission Rate (lb/hr)	Total PTE for 8 Turbines (tpy)
NOx	166.98	5851.11
CO	53.96	1890.86
VOC	13.55	474.74
SO_2	42.04	1472.92
PM_{10}	25.01	876.45

Combustion Turbine Potential to Emit Calculation - After Control or Federally Enforceable Limits

Combustion Turbine - Natural Gas					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1158.00 MMBtu/hr	0.0276 lb/MMbtu	31.96	31.96 tons/yr	255.69 tons/yr
CO	1158.00 MMBtu/hr	0.0466 lb/MMbtu	53.96	53.96 tons/yr	431.70 tons/yr
VOC	1158.00 MMBtu/hr	0.0018 lb/MMbtu	2.08	2.08 tons/yr	16.68 tons/yr
SO_2	1158.00 MMBtu/hr	0.0052 lb/MMbtu	6.02	6.02 tons/yr	48.17 tons/yr
PM_{10}	1158.00 MMBtu/hr	0.0095 lb/MMbtu	11.00	11.00 tons/yr	88.01 tons/yr

Combustion Turbine - Distillate Oil					
Pollutant	Heat Input	Emission Factor	lb/hr	PTE/CT	Total PTE
NOx	1158.00 MMBtu/hr	0.1442 lb/MMbtu	166.98	41.75 tons/yr	333.97 tons/yr
CO	1158.00 MMBtu/hr	0.0371 lb/MMbtu	42.96	10.74 tons/yr	85.92 tons/yr
VOC	1158.00 MMBtu/hr	0.0117 lb/MMbtu	13.55	3.39 tons/yr	27.10 tons/yr
SO_2	1158.00 MMBtu/hr	0.0363 lb/MMbtu	42.04	10.51 tons/yr	84.07 tons/yr
PM_{10}	1158.00 MMBtu/hr	0.0216 lb/MMbtu	25.01	6.25 tons/yr	50.03 tons/yr

Pollutant	Emission Rate (lb/hr)	Total PTE for 8 Turbines (tpy)
NOx	166.98	589.65
CO	53.96	517.63
VOC	3.39	43.77
SO_2	10.51	132.24
PM_{10}	11.00	138.03

Startup/Shutdown Emissions

Simple Cycle Operation

Estimated max number of startups/shutdown for natural gas per year	180
Estimated max number of startups/shutdown for diesel fuel per year	60

Natural Gas

Emissions from Simple Cycle Operation				
Pollutant	Startup Emission (lb/startup)	Shutdown Emission (lb/shutdown)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	20.7	11	2.85	22.82
CO	65.5	58.9	11.20	89.57

Diesel Fuel

Emissions from Simple Cycle Operation				
Pollutant	Startup Emission (lb/startup)	Shutdown Emission (lb/shutdown)	Emission Rate/Turbine (tons/yr)	Total Emission Rate (tons/yr)
NO_X	31.6	17.5	1.47	11.78
CO	76.4	65.5	4.26	34.06

Combustion Turbine Potential to Emit Calculations for HAPs

Natural Gas Turbine					
Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Turbine (tpy)	Total PTE (tpy)	Limited Total PTE (tpy)
Benzene	1.18E-05	0.0137	0.060	0.479	0.109
Formaldehyde*	2.61E-04	0.3022	1.324	10.590	2.418
Xylenes	6.28E-05	0.0727	0.319	2.548	0.582
Ethylbenzene	3.14E-05	0.0364	0.159	1.274	0.291
1,3 Butadiene	4.20E-07	0.0005	0.002	0.017	0.004
Napthalene	1.28E-06	0.0015	0.006	0.052	0.012
Toluene	1.28E-04	0.1482	0.649	5.194	1.186
PAH	2.16E-06	0.0025	0.011	0.088	0.020
Acrolein	6.28E-06	0.0073	0.032	0.255	0.058
Acetaldehyde	3.90E-05	0.0452	0.198	1.582	0.361
			single HAP	10.59	2.42
			combined HAP	22.08	5.04

Distillate Oil-Fired Turbine					
Pollutant	Emission Factor (lb/MMBtu)	Emission Rate (lb/hr)	PTE/Turbine (tpy)	Total PTE (tpy)	Limited Total PTE (tpy)
1,3 Butadiene	1.60E-05	0.0185	0.081	0.649	0.037
Benzene	5.50E-05	0.0637	0.279	2.232	0.127
Formaldehyde	2.80E-04	0.3242	1.420	11.361	0.648
Naphthalene	3.50E-05	0.0405	0.178	1.420	0.081
PAHs	4.00E-05	0.0463	0.203	1.623	0.093
Arsenic	1.10E-05	0.0127	0.056	0.446	0.025
Beryllium	3.10E-07	0.0004	0.002	0.013	0.001
Cadmium	4.80E-06	0.0056	0.024	0.195	0.011
Chromium	1.10E-05	0.0127	0.056	0.446	0.025
Lead	1.40E-05	0.0162	0.071	0.568	0.032
Manganese	7.90E-04	0.9148	4.007	32.055	1.830
Mercury	1.20E-06	0.0014	0.006	0.049	0.003
Nickel	4.60E-06	0.0053	0.023	0.187	0.011
Selenium	2.50E-05	0.0290	0.127	1.014	0.058
			single HAP	32.06	1.83
			combined HAP	52.26	2.98

Emission Calculation for Emergency Diesel Fire Pump

Maximum Hours of Operation 500 hrs/yr

Horsepower 150 hp

Weight Percent Sulfur 0.05 %

Pollutant	Emission Factor (lb/hp-hr)	Emission Rate (lb/hr)	PTE (tons/yr)
NOX	0.031	4.650	1.163
CO	0.00668	1.002	0.251
VOC	0.00247	0.371	0.093
SO2	0.000362	0.054	0.014
PM10	0.0022	0.330	0.083

*Emission factors based on AP-42 Table 3.3-2, 3.4-1, and 3.4-2

Appendix B - Air Quality Analysis

Source Name: Duke Energy Knox, LLC
Source Location: Corner of SE1275E and SE300S, Wheatland, Indiana 47597
County: Knox
Construction Permit No.: CP-083-12674-00043
SIC Code: 4911

Introduction

Duke Energy Knox, LLC (Knox Generating Station) has applied for a Prevention of Significant Deterioration (PSD) permit to construct and operate a simple-cycle power plant near Wheatland in Knox County, Indiana. The site is located at Universal Transverse Mercator (UTM) coordinates 472248.7 East and 4285661.0 North or 2 miles north of Wheatland. The peaking power plant would consist of eight 80 megawatts (MW) GE 7EA natural gas fired simple-cycle combustion turbines with fuel oil back-up and a small emergency fire-water pump diesel engine. Knox County is designated as attainment for the National Ambient Air Quality Standards. These standards for Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Particulate Matter less than 10 microns (PM_{10}) are set by the United States Environmental Protection Agency (U.S. EPA) to protect the public health and welfare.

ENSR Corp. prepared the PSD permit application for Knox Generating Station. The permit application was received by the Office of Air Quality (OAQ) on September 5, 2000. This document provides OAQ=s Air Quality Modeling Section's review of the PSD permit application including an air quality analysis performed by the OAQ.

Air Quality Analysis Objectives

The OAQ review of the air quality impact analysis portion of the permit application will accomplish the following objectives:

A. Establish which pollutants require an air quality analysis based on source emissions.
B. Determine the ambient air concentrations of the source's emissions and provide analysis of actual stack height with respect to Good Engineering Practice (GEP).
C. Demonstrate that the source will not cause or contribute to a violation of the National Ambient Air Quality Standard (NAAQS) or Prevention of Significant Deterioration (PSD) increment.
D. Perform an analysis of any air toxic compound for the health risk factor on the general population.
E. Perform a brief qualitative analysis of the source's impact on general growth, soils, vegetation and visibility in the impact area with emphasis on any Class I areas. The nearest Class I area is Kentucky's Mammoth Cave National Park, which is 187 kilometers or 116 miles from the proposed power plant in Knox County, Indiana.

Summary

Duke Energy Knox, LLC has applied for a PSD construction permit to construct and operate a simple cycle power facility, 2 miles north of Wheatland in Knox County, Indiana. The PSD application was prepared by ENSR Corp. of Warrenville, Illinois. Knox County is currently designated as attainment for all criteria pollutants. Emission rates of five pollutants (Nitrogen Dioxide (NO_2), Sulfur Dioxide (SO_2), Carbon Monoxide (CO), Particulate Matter less than 10 microns (PM_{10}) and Volatile Organic Compounds (VOCs)) associated with the proposed power facility exceeded significant emission rates established in state and federal law, thus requiring air quality modeling. Modeling results taken from the Industrial Source Complex Short Term (ISCST3) model showed all pollutant impacts were predicted to be less than the significant impact levels and significant monitoring de minimis levels for purposes of a National Ambient Air Quality Standards analysis. OAQ conducted Hazardous Air Pollutant (HAPs) modeling and all HAP 8-hour maximum concentrations modeled below 0.5% of each Permissible Exposure Limit (PEL). There was no impact review conducted for the nearest Class I area, which is Mammoth Cave National Park in Kentucky, due to the modeled concentrations from the source falling below significant impact increments for both Class I and Class II areas. An additional impact analysis on the surrounding area was conducted and no significant impact on economic growth, soils, vegetation, federal and state endangered species or visibility from the proposed facility was expected.

Part A - Pollutants Analyzed for Air Quality Impact

Indiana Administrative Code (326 IAC 2-2) PSD requirements apply in attainment and unclassifiable areas and require an air quality impact analysis of each regulated pollutant emitted in significant amounts by a new major stationary source or modification. Significant emission levels for each pollutant are defined in 326 IAC 2-2-1. CO, NO_x, SO_2, VOCs and PM_{10} will be emitted from Knox Generating Station and an air quality analysis is required for CO, NO_x, SO_2, VOCs and PM_{10}, all of which exceeded their significant emission rates as shown in Table 1. It should be noted that all emissions are based on the Best Available Control Technology (BACT) determination and other limitations resulting from the OAQ review of the application.

TABLE 1 - Knox Generating Station Significant Emission Rates (tons/yr)

Pollutant	Maximum Allowable Emissions	Significant Emission Rate
CO	641.5	100.0
NO_x	625.4	40.0
SO_2	132.0	40.0
PM_{10}	138.0	15.0
VOC (ozone)	113.0	40.0

Significant emission rates are established to determine whether a source is required to conduct an air quality analysis. If a source exceeds the significant emission rate for a pollutant, air dispersion modeling is required for that specific pollutant. A modeling analysis for each pollutant is conducted to determine whether the source modeled concentrations will exceed significant impact levels. Modeled concentrations below significant impact levels are not required to conduct further air quality modeling. Modeled concentrations exceeding the significant impact level will require more refined modeling which includes source inventories and background data. These procedures are defined in AGuidelines for Air Quality Maintenance Planning and Analysis, Volume 10, Procedures for Evaluating Air Quality Impacts of New Stationary Sources@ October 1977, U.S. EPA Office of Air Quality Planning and Standards (OAQPS).

Part B - Significant Impact Analysis

An air quality analysis, including air dispersion modeling, was performed to determine the maximum concentrations of the source emissions on receptors outside of the facility property lines. There were twelve different operating scenarios modeled to determine worst-case conditions from the two turbines. Normal operating loads of 60, 75 and 100 percent and 100 percent at five ambient air temperatures of -25^o F, 29^o F, 52^o F, 84^o F and 104^o F for natural gas and fuel oil-firings were modeled. Short-term worst-case emission determinations for each pollutant are summarized in Table 2. Emission rates and modeling results for each worst-case determination per unit can be found in Appendix A and the modeled emission rates including the start-up and shutdown emissions are listed in Appendix B.

TABLE 2 - Summary of Short-Term Worst-Case Emission Rate Determinations					
Pollutant	**Time-Averaging Period**	**Percent Load**	**Temperature (F)**	**Emission Rate per unit (g/sec)**	**Emission Rate per unit (tons/yr)**
CO	1 and 8-hour	100 %	-25^{o} F	9.866	343.24
SO_2	3 and 24-hour	100 %	-25^{o} F	1.843	64.12
PM_{10}	24-hour	100 %	-25^{o} F	3.484	121.21

Model Description

The Office of Air Quality review used the Industrial Source Complex Short-Term (ISCST3) model, Version 3, dated April 10, 2000 to determine maximum off-property concentrations or impacts for each pollutant. All regulatory default options were utilized in the United States Environmental Protection Agency (U.S. EPA) approved model, as listed in the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The Auer Land Use Classification scheme was referenced to determine the land use in a 3-kilometer (1.9-mile) radius from the source. The area is considered agricultural; therefore a rural classification was used. The model also utilized the Schulman-Scare algorithm to account for building downwash effects. Stacks associated with the proposed simple cycle power facility are below the Good Engineering Practice (GEP) formula for stack heights. This indicates that wind flow over and around surrounding buildings can influence the dispersion of concentrations coming from the stacks. 326 IAC 1-7-3 requires a study to demonstrate that excessive modeled concentrations will not result from stacks with heights less than the GEP stack height formula. These aerodynamic downwash parameters were calculated using U.S. EPA=s Building Profile Input Program (BPIP).

Meteorological Data

The meteorological data used in the ISCST3 model consisted of surface data from the Evansville, Indiana Airport National Weather Service station merged with the mixing heights from Peoria, Illinois Airport National Weather Service Station for the five-year period (1987-1991). The 1987-1991 meteorological data was obtained from the U.S. EPA Support Center for Regulatory Air Model electronic Bulletin Board and preprocessed into ISCST3 format with U.S. EPA=s PCRAMMET program.

Receptor Grid

Ground-level points (receptors) surrounding the source are input into the model to determine the maximum modeled concentrations that will occur at each point. OAQ modeling utilized receptor grids out to 20 kilometers (12.4 miles) for all pollutants. Dense receptor grids surrounded the property with receptors spaced every 100 meters (328 feet) out to 2 kilometers (1.25 miles), receptors spaced every 500 meters (1640 feet) from 2 kilometers to 5 kilometers (3.1 miles), receptors spaced every 1000 meters (3280 feet) from 5 kilometers to 10 kilometers (6.2 miles) and 2000 meters (6560 feet) from 10 kilometers to 20 kilometers. Discrete receptors were placed 50 meters or 164 feet apart on Knox Generating Station property lines and also at areas where potentially sensitive groups might be located, such as schools, parks, hospitals or penitentiaries.

Modeled Results

Maximum modeled concentrations for each pollutant over its significant emission rate are listed below in Table 3 and are compared to each pollutant=s significant impact level for Class II areas, as specified by U.S. EPA in Federal Register, Volume 43, No. 118, page 26398 Monday, June 19, 1978.

TABLE 3 – Summary of OAQ Significant Impact Analysis (ug/m3)

Pollutant	**Year**	**Time-Averaging Period**	**Knox Maximum Modeled Impacts**	**Significant Impact Levels**	**Significant Monitoring Levels**
CO	1987	1-hour	895.27	**2000.0**	[a]
CO	1989	8-hour	51.50	**500.0**	575.0
NO_2	1987	Annual	0.67	**1.0**	14.0
SO_2	1990	3-hour	13.69	**25.0**	[a]
SO_2	1989	24-hour	1.92	**5.0**	13.0
SO_2	1991	Annual	0.01	**1.0**	[a]
PM_{10}	1990	24-hour	1.74	**5.0**	10.0
PM_{10}	1987	Annual	0.04	**1.0**	[a]

[a] No limit exists for this time-averaged period

All modeled concentrations for each pollutant at all applicable time-averaged periods were below both the significant impact level and significant monitoring de minimis levels. No excessive concentrations will result due to stack heights less than the GEP stack height formula. Existing air quality concentrations as recorded by monitors throughout the area are below National Ambient Air Quality Standards for each pollutant. No significant short-term or long-term health impacts are expected as a result of the proposed facility and no further refined air quality analysis is required as well as no pre-construction monitoring requirements.

Particulate Matter less than 2.5 micron

U.S. EPA issued a new National Ambient Air Quality Standard for Particulate Matter less than 2.5 microns ($PM_{2.5}$) on July 17, 1997. Due to a legal challenge to the new standard, however, U.S. EPA has released specific guidance stating that states should continue to analyze PM_{10} impacts for all New Source Review. There are 3 primary origins of $PM_{2.5}$: 1) primary particulates in the solid state, 2) condensible particulates and 3) secondary particulates formed through atmospheric reactions of gaseous precursor emissions. There will be a five-year scientific review of this standard which includes installation of $PM_{2.5}$ monitors throughout the state to better define background concentrations and gather source specific information. U.S. EPA is expected to release a new dispersion model to better predict $PM_{2.5}$ concentrations. There is no assumed ratio of $PM_{2.5}$ to PM_{10} at this time. No modeling for $PM_{2.5}$ was conducted.

Part C - Ozone Impact Analysis

Ozone formation tends to occur in hot, sunny weather when NOx and VOC emissions photochemically react to form ozone. Many factors such as light winds, hot temperatures and sunlight are necessary for higher ozone production. As per OAQ instruction, ENSR submitted its own ozone transport analysis from the proposed Knox Generating Station facility. This included a wind rose analysis and the

Reactive Plume Model (RPM-IV) analysis, which ENSR has used in previous ozone analysis for other projects. The results of the wind rose analysis and the RPM-IV modeling show that any potential ozone impacts from the facility would occur to the northeast and relatively close to the facility.

OAQ Three-Tiered Ozone Review

OAQ incorporates a three-tiered approach in evaluating ozone impacts from a single source. The first step is to determine how NOx and VOC emissions from the new source compare to area-wide NOx and VOC emissions from Knox County as well as the surrounding counties of Daviess, Gibson, Greene, Pike and Sullivan. Results from this analysis show Knox Generating Station=s 340.0 tons/yr of NOx would comprise 1% of the area-wide NOx emissions from point, area, onroad and nonroad mobile source and biogenic emissions (naturally-occurring emissions from trees, grass and plants). Knox Generating Station=s 113.0 tons/yr of VOC emissions would comprise less than 1% of the area-wide VOC emissions from the different sources listed above.

A second step is to review historical monitored data to determine ozone trends for an area and the applicable monitored value assigned to an area for designation determinations. This value is known as the design value for an area. The nearest ozone monitor within this region is the Wheeling monitor in Gibson County which is 35 kilometers or 22 miles to the southwest of the proposed site. This monitor is considered upwind of the proposed facility. The design value for the Wheeling monitor for the 1-hour ozone standard over the latest three years of monitoring data has not yet been established because the monitor was brought online in 1999. The highest 1-hour reading at the monitor is 106 parts per billion (ppb). Two other ozone monitors in the area would be the Lynnville monitor located in Warrick County approximately 58 kilometers (36 miles) to the south and the Inglefield monitor located in Vanderburgh County, approximately 70 kilometers (43 miles) to the south of the proposed site. The design value for the Lynnville monitor is 108 ppb while the design value for the Inglefield monitor is 110 ppb. These monitors are considered upwind of the proposed facility. Wind rose analysis indicates that prevailing winds in the area occur from the southwest and west-southwest during the summer months of May through September when ozone formation is most likely to occur. Ozone impacts from Knox Generating Station would likely fall north, northeast and east northeast of the facility.

A third step in evaluating the ozone impacts from a single source is to estimate the source individual impact through a screening procedure. The Reactive Plume Model-IV (RPM-IV) has been used in past air quality reviews to determine 1-hour ozone impacts from single VOC/NOx source emissions. RPM-IV is listed as an alternative model in Appendix B to the 40 Code of Federal Register Part 51, Appendix W AGuideline on Air Quality Models@. The model is unable to simulate all meteorological and chemistry conditions present during an ozone episode (period of days when ozone concentrations are high). Results from RPM-IV are an estimation of potential ozone impacts. Modeling for 1 hour ozone concentrations was conducted for June 18, 1994 (a high ozone day) to compare to the ozone National Ambient Air Quality Standard (NAAQS) limit. The maximum cell concentration of ozone for each time and distance specified was used to compare to the ambient ozone. OAQ modeling results assumed the short-term emission rates of NO_2 and VOCs and are shown in Appendix C. The impact (difference between the plume-injected and ambient modes) from Knox Generating Station was 1.2 ppb early in the plume development. All ambient plus plume-injected modes were below the NAAQS limit for ozone at every time period and every distance. No modeled 1-hour NAAQS violations of ozone occurred.

Urban Airshed Model (UAM) analysis for regional ozone transport has been conducted by OAQ as well as states surrounding Lake Michigan and various national organizations. UAM is regarded as a regional modeling tool used to develop ozone attainment demonstrations and determine NOx and VOC emission controls for a region. Transport of ozone and ozone-forming pollutants from upwind areas is evident and would likely contribute to increased ozone concentrations in Knox County. Previous experience with this model has shown that the amount of additional NOx and VOC emission from Knox Generating Station, which are a tiny fractions of the pollutants regionally, would not noticeably increase the ozone concentrations in the area.

From this three-tiered approach, ozone formation is a regional issue and the emissions from Knox Generating Station will represent a small fraction of NOx and VOC emissions in the area. Ozone contribution from Knox Generating Station emissions is expected to be minimal. Ozone historical data shows that the area monitors have design values below the ozone NAAQS of 120 ppb and the Knox Generating Station ozone impact based on the emissions and modeling will have minimal impact on ozone concentrations in the area.

Part E - Hazardous Air Pollutant Analysis and Results

As part of the air quality analysis, OAQ requests data concerning the emission of 188 Hazardous Air Pollutants (HAPs) listed in the 1990 Clean Air Act Amendments which are either carcinogenic or otherwise considered toxic. These substances are listed as air toxic compounds on the State of Indiana, Department of Environmental Management, Office of Air Quality=s construction permit application Form Y. Any one HAP over 10 tons/year or all HAPs with total emissions over 25 tons/year will be subject to toxic modeling analysis. The modeled emissions for each HAP are the total emissions based on assumed operation of 8760 hours per year.

OAQ performed toxic modeling using the ISCST3 model for all HAPs. Maximum 8-hour concentrations were determined and the concentrations were recorded as a percentage of each HAP Permissible Exposure Limit (PEL). The PELs were established by the Occupational Safety and Health Administration (OSHA) and represent a worker=s exposure to a pollutant over an 8-hour work day or a 40-hour work week. In Table 4 below, the results of the HAP analysis with the emission rates, modeled concentrations and the percentages of the PEL for each HAP are listed. All HAPs concentrations were modeled below 0.5% of their respective PELs. The 0.5% of the PEL represents a safety factor of 200 taken into account when determining the health risk of the general population.

TABLE 4 - Hazardous Air Pollutant Analysis

Hazardous Air Pollutants	Total HAP Emissions	Limited HAP Emissions	Maximum 8-hour concentrations	PEL	Percent of PEL
	(tons/year)	(tons/year)	(ug/m3)	(ug/m3)	(%)
1,3 Butadiene	0.739	0.0447	0.004886	2200000.0	0.0000002
Acetaldehyde	1.712	0.39	0.046582	360000.0	0.00001
Acrolein	0.27353	0.0624	0.005899	250.0	0.0024
Benzene	0.6925	0.265	0.058298	3200.0	0.0018
Ethyl Benzene	1.37	0.312	0.005516	435000.0	0.000001
Formaldehyde	11.67	3.21	0.111337	930.0	0.012
Naphthalene	0.15	0.102	0.006276	50000.0	0.0000126
PAHs	0.197	0.124	0.015877	100.0	0.0159
Propylene Oxide	1.25	0.283	0.138546	240000.0	0.00006
Toluene	2.86	0.653	0.032704	750000.0	0.0000044
Xylene	2.73	0.624	0.025797	435000.0	0.0000059
Metallic Hazardous Air Pollutants					
Arsenic	0.491	0.028	0.001980	10.0	0.0198
Beryllium	0.014	0.00079	0.000056	2.0	0.0028
Cadmium	0.213	0.0122	0.000861	5.0	0.0172
Chromium	0.491	0.028	0.001980	500.0	0.000396
Lead	0.612	0.036	0.002510	50.0	0.00502

Manganese	35.08	2.003	0.141607	5000.0	0.0028
Mercury	0.053	0.003	0.000216	100.0	0.00022
Nickel	0.21	0.012	0.000826	1000.0	0.000083
Selenium	1.11	0.064	0.004490	200.0	0.0022

[a] No OSHA PEL for 8-hour exposure exists at this time

Part F - Additional Impact Analysis

PSD regulations require additional impact analysis be conducted to show that impacts associated with the facility would not adversely affect the surrounding area. The Knox Generating Station PSD permit application provided an additional impact analysis performed by ENSR. This analysis included an impact on economic growth, soils, vegetation and visibility and is listed in Section 6.5 of their application.

Economic Growth and Impact of Construction Analysis

A construction workforce of 120 is expected and Knox Generating Station will employ up to 12 people selected from the local and regional area once the facility is operational. Secondary emissions are not expected to significantly impact the area as all roadways will be paved. Industrial and residential growth is predicted to have negligible impact in the area since it will be dispersed over a large area and new home construction is not expected to significantly increase. Any commercial growth, as a result of the proposed power facility, will occur at a gradual rate and will be accounted for in the background concentration measurements from air quality monitors. A minimal number of support facilities will be needed. There will be no adverse impact in the area due to industrial, residential or commercial growth.

Soils Analysis

Secondary NAAQS limits were established to protect general welfare, which includes soils, vegetation, animals and crops. Soil types in Knox County are of the Sylvan-Alford-Hosmer Associations of which is predominately thick Loess or wind blown silt belt (Soil Survey of Knox County, U.S. Department of Agriculture). The general landscape consists of Wabash Lowland or flat to gently rolling terrain (1816-1966 Natural Features of Indiana - Indiana Academy of Science). According to the insignificant modeled concentrations CO, NO_2, SO_2 and PM_{10} and the HAPs analysis, the soils will not be adversely affected by the proposed facility.

Vegetation Analysis

Due to the agricultural nature of the land, crops in the Knox County area consist mainly of corn, soybeans, wheat and hay (1997 Agricultural Census for Knox County). The maximum modeled concentrations of the proposed power facility for CO, NO_2, SO_2 and PM_{10} are well below the threshold limits necessary to have adverse impacts on surrounding vegetation such as autumn bent, nimblewill, barnyard grass, bishopscap and horsetail milkweed (Flora of Indiana - Charles Deam). SO2 sensitivity screening results show 1-hour and 3-hour modeling results would fall well below sensitivity values established by U.S. EPA in AA Screening Procedure for the Impacts of Air Pollution Sources on Plants, Soils and Animals@. Livestock in the county consist mainly of hogs, beef and milk cows and sheep (1997 Agricultural Census for Knox County) and will not be adversely impacted from Knox Generating Station. Trees in the area are mainly Beech, Maple, Oak and Hickory. These are hardy trees and due to the insignificant modeled concentrations, no significant adverse impacts are expected.

Federal and State Endangered Species Analysis

Federally endangered or threatened species as listed in the U.S. Fish and Wildlife Service , Division of Endangered Species for Indiana include 12 species of mussels, 4 species of birds, 2 species of bat and butterflies and 1 specie of snake. The mussels and birds listed are commonly found along major rivers and lakes while the bats are found near caves. The agricultural nature of the land overall has disturbed the habitats of the butterflies and snake and the proposed facility is not expected to impact the area.

Federally endangered or threatened plants as listed in the U.S. Fish and Wildlife Service Division endangered plant is found along the sand dunes in northern Indiana while the two threatened species do not thrive on cultivated or grazing land. The proposed facility is not expected to impact the area.

The state of Indiana=s list of endangered, special concern and extirpated nongame species, as listed in the Department of Natural Resources, Division of Fish and Wildlife, contains species of birds, amphibians, fish, mammals, mollusks and reptiles which may be found in the area of the Knox Generating Station. However, the impacts are not expected to have any additional adverse effects on the habitats of the species than what has already occurred from the agricultural activity in the area.

Additional Analysis Conclusions

The nearest Class I area to the proposed power facility is the Mammoth Cave National Park located approximately 261 km southwest in Kentucky. Operation of the proposed power facility will not adversely affect the visibility at this Class I area. The results of the additional impact analysis conclude the Knox Generating Station's proposed power facility will have no adverse impact on economic growth, soils, vegetation, endangered or threatened species or visibility on any Class I area.

APPENDIX A - Worst-Case Scenario Determination for 8 units for Knox Generating Station						
Scenario #1 (Load at 100% at 104^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.167	26.380		8.140		
NO_2	3.723					0.230
PM_{10}	3.459				0.307	0.023
SO_2	1.676		1.490		0.370	0.028
Scenario #2 (Load at 100% at 52.3^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.185	59.010		19.790		
NO_2	3.736					0.203
PM_{10}	3.465				0.357	0.027
SO_2	1.682		1.410		0.345	0.026
Scenario #3 (Load at 100% at -25^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.866	108.920		19.800		
NO_2	4.095					0.188
PM_{10}	3.484				0.395	0.029
SO_2	1.843		1.470		0.336	0.025
Scenario #4 (Load at 100% without duct firing at 104^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.167	26.380		8.140		
NO_2	3.723					0.230
PM_{10}	3.459				0.307	0.023
SO_2	1.676		1.490		0.370	0.028
Scenario #5 (Load at 100% without duct firing at 52.3^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.185	59.010		19.790		
NO_2	3.736					0.203
PM_{10}	3.465				0.357	0.027
SO_2	1.682		1.410		0.345	0.026
Scenario #6 (Load at 100% without duct firing at -25^{o} F)						
	Emission Rates per unit (g/sec)	**Maximum Concentrations (ug/m3)**				

Pollutant		1-hour	3-hour	8-hour	24-hour	Annual
CO	9.866	108.920		19.800		
NO_2	4.095					0.188
PM_{10}	3.484				0.395	0.029
SO_2	1.843		1.470		0.336	0.025
Scenario #7 (Load at 75% at 104^o F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.167	26.380		8.140		
NO_2	3.723					0.230
PM_{10}	3.459				0.307	0.023
SO_2	1.676		1.490		0.370	0.028
Scenario #8 (Load at 75% at 52.3^o F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.185	59.010		19.790		
NO_2	3.736					0.203
PM_{10}	3.465				0.357	0.027
SO_2	1.682		1.410		0.345	0.026
Scenario #9 (Load at 75% at -25^o F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.866	108.920		19.800		
NO_2	4.095					0.188
PM_{10}	3.484				0.395	0.029
SO_2	1.843		1.470		0.336	0.025
Scenario #10 (Load at 60% at 104^o F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.167	26.380		8.140		
NO_2	3.723					0.230
PM_{10}	3.459				0.307	0.023
SO_2	1.676		1.490		0.370	0.028
Scenario #11 (Load at 60% at 52.3^o F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.185	59.010		19.790		
NO_2	3.736					0.203

PM_{10}	3.465				0.357	0.027
SO_2	1.682		1.410		0.345	0.026
Scenario #12 (Load at 60% at -25^{o} F)						
Pollutant	**Emission Rates per unit (g/sec)**	**Maximum Concentrations (ug/m3)**				
		1-hour	**3-hour**	**8-hour**	**24-hour**	**Annual**
CO	9.866	108.920		19.800		
NO_2	4.095					0.188
PM_{10}	3.484				0.395	0.029
SO_2	1.843		1.470		0.336	0.025

APPENDIX B - Worst-Case Modeled emission rates for Knox Generating Station				
Pollutant	**Emissions rate per unit**	**Start-up/Shutdown emission rate per unit**	**Total Emission Rate per unit**	**Total Emissions for all 8 units**
	(grams/sec)	(grams/sec)	(grams/sec)	(tons/yr)
CO	9.866	0.011	15.874	4418.05
NO_2	4.095	0.007	6.687	1861.13
PM_{10}	3.484	0.003	0.669	186.20
SO_2	1.843	0.002	0.808	224.88

APPENDIX C - RPM-IV Modeling for Knox Generating Station				
NAAQS Analysis for Ozone (June 20, 1994)				
Time	**Distance**	**Ambient**	**Plume-Injected**	**Source Impact**
(hours)	(meters)	(ppb)	(ppb)	(ppb)
700.0	116.0	34.6	35.8	1.2
800.0	5060.0	53.5	21.2	-32.3
900.0	13000.0	71.3	60.3	-11
1000.0	27000.0	87.4	78.9	-8.5
1100.0	39600.0	101	93.1	-7.9
1200.0	55600.0	112	106	-6
1300.0	74400.0	119	117	-2
1400.0	93900.0	122	121	-1
1500.0	114000.0	124	122	-2
1600.0	432000.0	124	122	-2
1700.0	150000.0	124	122	-2
1800.0	163000.0	124	122	-2
1900.0	169000.0	124	122	-2

Appendix C

BEST AVAILABLE CONTROL TECHNOLOGY (BACT) REVIEW

Source Name:	Duke Energy Knox, LLC
Source Location:	Corner of SE1275E and SE300S, Wheatland, Indiana 47597
County:	Knox
Construction Permit No.:	CP-083-12674-00043
SIC Code:	4911
Permit Reviewer:	David Howard

The Office of Air Quality (OAQ) has preformed the following federal BACT review for the proposed electrical power generation plant to be owned and operated by Duke Energy Knox LLC (Duke), located in Wheatland, Indiana. This review was preformed for the eight natural gas-fired combustion turbines.

The source is located in Knox County, which has been designated as attainment or unclassifiable for PM/PM_{10}, NO_X, CO, SO_2, and VOC. Therefore, these pollutants were reviewed pursuant to the PSD Program (326 IAC 2-2 and 40 CFR 52.21). PM/PM_{10}, NO_X, CO, SO_2, and VOC are subject to BACT review because the pollutant emissions are above PSD significant threshold levels stated in 326 IAC 2-2-1. BACT is an emission limitation based on the maximum degree of reduction of each pollutant subject to the PSD requirements. In accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outline in the 1990 draft USEPA *New Source Review Workshop Manual*, this BACT analysis takes into account the energy, environment, and economic impacts on the source. These reductions may be determined through the application of available control technologies, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause or contribute to air pollution thereby protecting public health and the environment.

(A) Eight Natural Gas-Fired Combustion Turbines

The eight combustion turbines will be General Electric Frame 7EA models equipped with General Electric's dry low-NO_X combustion technology system. The maximum heat input rating for each combustion turbine at ISO conditions is 1,158 MMBtu per hour. The combustion turbines will be operated in simply cycle mode as a peaking plant facility. The output of each combustion turbine, while operating in simple cycle mode is approximately 80 MW.

(1) NO_X BACT Review

Nitrogen oxide formation during combustion consists of three types, thermal NO_X, prompt NO_X, and fuel NO_X. The principal mechanism of NO_X formation during combustion is thermal NO_X. The thermal NO_X mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen and oxygen molecules in the combustion air. Most NO_X formed through the thermal NO_X is affected by three factors: oxygen concentration, peak temperature, and time of exposure at peak temperature. As these factors increase, NO_X emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired turbines. Emission levels vary considerably with the type and size of combustor and with operating conditions (i.e. combustion air temperature, volumetric heat release rate, load, and excess oxygen level). The second mechanism of NO_X formation, prompt NO_X, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_X, reactions occur within the flame and are typically negligible when compared to the amount on NO_X formed through the thermal NO_X mechanism. The final mechanism of NO_X formation, fuel NO_X, stems from the evolution and reaction of fuel-bonded nitrogen compounds with oxygen. Characteristically natural gas contains low fuel nitrogen content, therefore, NO_X formation through the fuel NO_X mechanism is insignificant when firing natural gas.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Catalytic Combustion (XONON)
Non-ammonia SCR (SCONOX)
Selective Non-catalytic Reduction (SNCR)
Selective Catalytic Reduction (SCR)
Dry Low NO_X Burners
Water/Steam Injection
Nonselective Catalytic Reduction (NSCR)

Technically Infeasible Control Options – Three of the control options are considered to be technically infeasible: XONON, SNCR, and NSCR. XONON is a front-end technology that uses an oxidation catalyst within the individual combustors to produce a lower flame temperature in turn reducing NO_X emissions. Catalytica, Inc. was the first to commercially develop catalytic combustion controls for smaller turbine models and markets the technology under the name of XONON. Catalytic combustion technology is not yet commercially available for any of the commercial turbines in Frame 7 size. Therefore, catalytic combustion is considered to be technically infeasible for the proposed facility.

SNCR is a back-end control technology uses ammonia injection to control NO_X. SNCR is similar to SCR, but it operates at a higher temperature range, 1,300 to 2,100 ^oF with an optimum temperature range from 1,600 to 1,900 ^oF. The simple cycle combustion turbines for the proposed facility will have a maximum exhaust temperature of approximately 1,100 ^oF. Therefore, additional fuel combustion would be required to achieve exhaust temperatures compatible with the SNCR operation. This temperature restriction makes SNCR technically infeasible for the proposed facility.

NSCR is another back-end control technology, which is only effective in controlling certain fuel-rich reciprocating engine combustion emissions, and requires the combustion of gas to be nearly depleted of oxygen to operate. Since combustion turbines operate with high levels of excess oxygen NSCR is not technically feasible for the proposed facility.

Ranking of Technically Feasible Control Options – The following technically feasible NO_X control options are ranked by control efficiency:

Rank	Control	Facility	Emission Limit (ppmvd)	Control Efficiency
1	SCONOx	Turbine	Less than 2.5	N/A
2	Selective Catalytic Reduction (SCR)	Turbine	2.5 – 4.5	60% - 90%
3	Dry Low NO_X Burners	Turbine	9	N/A
4	Water/Steam Injection	Turbine	25 – 75	N/A

Discussion – SCONOx is an emerging technology, which offers promise of reducing combustion turbine NO_X emissions to values less than 2.5 ppm. SCONOx technology uses an oxidation/adsorption/regeneration cycle across a catalyst bed to achieve back-end reduction of NO_X. Unlike SCR, the system does not require the injection of ammonia as a reagent, instead parallel catalyst that are alternately taken off-line for regeneration through the means of mechanical dampers. The catalyst works simultaneously by oxidizing CO to CO_2, NO to NO_2, and then absorbing NO_2. The NO_2 is absorbed into potassium carbonate catalyst coating as KNO_2 and KNO_3. Then the catalyst becomes loaded with potassium nitrates and nitrates, it is taken off-line and isolated from the flue gas stream with mechanical dampers for regeneration. The regeneration process occurs by introducing hydrogen. In the absence of oxygen, hydrogen reacts with potassium nitrates and nitrates during regeneration to form H_2O and N_2, which is emitted from the stack.

SCONOx has been demonstrated in practice on the 32 MW combined cycle Sunlaw Energy Federal facility in California with emissions demonstrated at 2-2.25 ppm range in 1997. A more recent 5 MW cogeneration combustion turbine facility has been installed at the Genetics Institute in Massachusetts. The SCONOx system at this facility operates at a narrow temperature range between 300 to 700 ^{o}F. Both of these facilities are considerably small than the proposed Duke Knox facility, at 80 MW per turbine. Long term maintenance and reliability concerns with the mechanical parts are still a concern with the larger turbines when using SCONOX.

Another factor that limits the use of SCONOx on gas turbines with similar characteristics as the turbines proposed, is cost effectiveness. The cost to control NOx and CO emissions are considerably high. Based on vendor quote, the capital cost of the SCONOx system is $6,300,000. Based on the total annual cost of $1,776,613, the average cost per ton removed of NOx and CO is $63,240. Therefore SCONOx will not be considered further as BACT for the proposed facility.

Selective Catalytic Reduction

SCR is a process, which involves post-combustion removal of NO_X from the flue gas stream with a catalytic reactor. In an SCR system, ammonia is injected into the turbine exhaust gas where it reacts with nitrogen oxides and oxygen to form nitrogen and water. The reactions take place on the surface of a catalyst. The function of the catalyst is to effectively lower the activation energy of the NO_X decomposition energy. Technical factors related to this technology include increased turbine back pressure, exhaust temperature materials limitations, thermal shock/stress during rapid starts, masking/blinding, catalyst failure, and NH_3 injection system. The catalysts are divided into two groups: base metal and zeolite. A disadvantage common to the base metal catalyst is the inability to operate at higher temperature ranges. Due to this inability to operate at a higher temperature range, the base metal catalyst are used on the combined cycle SCR system where the exhaust gas is routed through a heat recovery steam generator. The zeolite catalyst is the only catalyst currently available that can operate at the temperature range typical of a simple cycle operation. Zeolite catalysts have a maximum temperature limit of 1,100 ^{o}F. Simple cycle operations often have short-term temperature excursion and thermal stresses associated with typical startup/shutdown applications of the simple cycle operation. According to a vendor, sustained operation at these temperatures or transient operation over these temperatures could result in permanent and premature damage to the catalyst.

There have only been three natural gas-fired simple cycle facilities that have utilized a high temperature catalyst system. The City of Redding Electrical Peaking Turbines experienced catalyst masking after only 550 hours of operation. A second facility, Southern California Gas experienced a catastrophic catalyst bed failure attributed to thermal shock. All three of the facilities that are utilizing the high temperature SCR system are considerably smaller than the proposed facility. The largest facility utilizing this technology is 42 MW per turbine, which is half the size of the proposed facilities turbines at 80 MW per turbine.

Based on 2,000 hours of operation per year per turbine on natural gas and 500 operating hours on diesel oil, the cost to control approximately 74 tons per year per turbine would have an overall cost effectiveness of $46,000 per ton of NO_X removed. This does not represent and economically feasible control option.

Based on the conclusion that a high temperature SCR system is not economically feasible, and the very limited successful operating history on simple-cycle peaking applications this technology will not be considered further as BACT for NO_X at this facility.

Water/Steam Injection and Dry Low-NOx Combustors

Water/steam injection and Low NOx combustors are common technologies viable for most turbines. The Dry Low-NOx combustors proposed by the source, when firing natural gas, will achieve NO_X emissions levels of 9 ppmvd corrected to 15% O_2. However diesel fuel cannot be premixed with air as easily as natural gas. For this reason, the source proposed the use of water injection with a NO_X emission level of 42 ppmvd corrected to 15% O_2, in conjunction with firing diesel fuel.

<u>Existing BACT Emission Limitations</u> – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The following table represents entries in the RBLC of similar operation.

Company	Facility	Throughput (per turbine)	Emission Rate (ppm@15%O2)	Control Description
Proposed Duke Knox Facility	Turbine (8)	1158 MMBtu/hr	9 (24 operating hour average)	Dry Low NO_X Combustor (DLN)
			42 (1-hr average)	Water Injection (WI)
LSP Kendall Energy	Turbine	4 x 190 MW	25 (1-hr average)	DLN
Lyondell Harris	Turbine	1 x 160 MW	25 (1-hr average)	DLN
Tenaska	Turbine	6 x 170 MW	15 (1-hr average)	DLN
			42 (1-hr average)	WI
Dynergy Heard	Turbine	3 x 170 MW	15 (1-hr average)	DLN
Vermillon Generating Station	Turbine	8 x 80 MW	15 (1-hr average), 12 (annual average)	DLN
			42 (1-hr average)	WI
Madison Generating Station	Turbine	8 x 80 MW	15 (1-hr average), 12 (annual average)	DLN
Georgia Power	Turbine	16 x 80 MW	15 (1-hr average); 9 (base load and 22 “peak”)	DLN
RockGen Energy	Turbine	Not specified	15 (1-hr average); 12 (24-hr average)	Good Combustion
Lee Generating Station	Turbine	8 x 80 MW	15 (1-hr average), 12 (annual average)	DLN
JEA Baldwin	Turbine	3 x 170 MW	10.5 (24-hr average)	DLN
			42 (1-hr average)	WI
Hardee Power Station	Turbine	1 x 75 MW	9 (24-hr average)	DLN
Tec Polk Power	Turbine	2 x 165 MW	10.5 (24-hr average)	DLN

			42 (1-hr average)	WI
Enron, Des Plaines	Turbine	8 x 83 MW	9 (annual average) 12 (monthly average), 15 (1-hr average)	DLN
Air Liquide	Turbine	Not specified	9 (annual average)	DLN
Wisconsin Public Service	Turbine	1 x 102 MW	9 (24-hr average) 20 (“peak power” mode limited to 100 hrs/yr)	DLN
Oleander Brevard	Turbine	3 x 170 MW	9 (24-hr average)	DLN
Vandolah Haredd	Turbine	4 x 170 MW	9 (24-hr average)	DLN
Enron, Kendall	Turbine	8 x 83 MW	9 (annual average), 12 (monthly average), 15 (1-hr average)	DLN
Wisconsin Electric	Turbine	1 x 85 MW	9 (24-hr average)	DLN
Dynergy Reidsville	Turbine	5 x 180 MW	25 (1-hr average), 15 (by retrofit)	DLN (retrofit)
LSP Nelson	Turbine	1,100 MW	15 (1-hr average)	Good Combustion
			42 (1-hr average)	WI
Wrightsville Power Facility	Turbine	Not specified	9 (24-hr average)	DLN

Based on recent EPA Region V data, there are several sources proposing NOx limits of 9 ppmvd at 15% O_2 for combustion turbines in conjunction with natural gas with a range of averaging times. The averaging periods range from annual to one (1) hour. In addition to the proposed BACT NOx limits of 9 ppmvd at 15% O_2 for natural gas, there have been combustion turbine permits recently issued with such limit as well. The table above lists the NOx BACT limits for turbines in conjunction with natural gas. This table lists issued and draft permits. Even though the NSR manual states that BACT can be based on issued permits, the OAQ interprets this as a minimum requirement and the OAQ can go above and beyond the guidance of the New Source Review (NSR) Manual.

As indicated on Table 1 listed above, the Air Liquide, Madison and Vermillion combustion turbine projects are in operation. Madison and Vermillion have limited CEMs operational data available. These two sites are similar to the proposed Duke Knox facility. Based on the Vermillion CEMs data submitted, the OAQ has determined that the source can maintain a 9 ppmvd at 15% O_2 limit during steady state operations. Air Liquide America Corporation recently received a permit from the Louisiana Department of Environmental Quality for a cogeneration project. This permit allows the turbines to emit up to 9 ppmvd of NO_x at 15 percent $O_{2,}$ over the 8,760 hours of expected annual operation in conjunction with natural gas. Additionally, compliance with this limit has been demonstrated by conducting three (3) one (1)-hour stack test runs under optimal conditions. Continuous emissions NO_x monitoring is not required on these base-load units. Therefore, due to this project being a cogeneration operation and also the fact that the permit does not require CEMS, this project is not considered comparable to the one proposed.

From EPA=s *New Source Review Workshop Manual* (October 1990, page B.7), Aa permit requiring the application of a certain technology or emission limit to be achieved for such technology usually is sufficient justification to assume the technical feasibility of that technology or emission limit@. Since there is very limited operational continuous emissions monitoring system (CEMS) data available for turbines designed to achieve 9 ppmvd @ 15% O_2, an issued permit with such emission limit is sufficient justification to require such emission limit as BACT. It is also evident that the Dry Low-NOx (DLN) combustor technology with a guaranteed emission rate of 9 ppmvd is considered available because the source obtained such guaranteed emission rate through commercial channels. This technology is considered Aapplicable@ because such guaranteed emission rate has been deployed (e.g. emission limit of 9 ppmvd @ 15% O_2 over a 24-hour average in an issued permit) on the same or similar source. Deployment of the emission limit by such control technology on an existing source with similar gas stream characteristics, is sufficient basis for concluding technical feasibility barring a demonstration to the contrary.

Currently, there is very limited operational CEMS data available for turbines guaranteed to achieve 9 ppmvd @ 15% O_2. Since such data is not extensive and not based on at least four (4) months of data, the Office of Air Quality (OAQ) has determined that a NOx limit of 9 ppmvd @15% O_2 over a 24 operating hour period is BACT. This determination is based on recent issued permits.

Even though there is an issued permit requiring a 9 ppmvd at 15% O_2 limit based over a one (1) -hour average, the OAQ believes that this averaging time is not flexible enough for this type of operation and may not be achievable based on the Vermillion Generating Stations operating data. A NOx limit of 9 ppmvd at 15% O_2 based over a 24 operating hour averaging time should allow for more operational flexibility. Due to the nature of peaking operations, there could be instances when these turbines come on-line for only one (1) hour. Therefore, it was concluded that a 9 ppmvd @ 15% O_2 limit based on a 24 operating hour averaging time under steady state conditions will limit the annual emissions and minimize the short term emissions from these units.

The OAQ determined that the non-steady state operations, including startups and shutdowns, need a separate limit outside of the limits established during normal or steady state operations. This decision is based on discussions with General Electric, reviewing other issued permits for this type of operation and reviewing the Vermillion Generating Station CEMS operational data. Therefore, startup and shutdown periods will have a different limit than the normal operation limit. Also from the supplied information, the OAQ was able to estimate the corresponding worst case emissions during a startup and shutdown cycle for all criteria pollutants. In addition, this project will have a maximum of 240 startup and shutdown cycles per year per turbine.

<u>Conclusion</u> – Based on the information presented above, the NO_X BACT for the eight combustion turbines shall be the use of natural gas as the primary fuel in conjunction with Dry Low-NOx combustors, and a operational limitation of 2,000 hours per year firing natural gas. The NO_X emissions from each turbine shall not exceed 9 ppmvd corrected to 15% O_2 averaged over a 24 operating hour period. This limit is equivalent to 31.96 pounds of NO_X per hour.

The NO_X BACT for the eight combustion turbines, when firing diesel fuel, shall be the use of water injection as NO_X control and a operational limitation of 500 hours per year firing diesel fuel. The NO_X emissions from each turbine shall not exceed 42 ppmvd corrected to 15% O_2 on a one (1) hour average. This limit is equivalent to 166.98 pounds of NO_X per hour.

For periods of startup/shutdown the each combustion turbine will be limited to 20.7 pounds of NO_X per startup, and 11 pounds per shutdown when firing natural gas. Each combustion turbines shall not exceed 31.6 pounds per startup, and 17.5 pounds per shutdown when firing diesel fuel. Also, the source will be limited to 240 startup/shutdowns per year.

(2) CO BACT Review

Carbon monoxide emissions from combustion turbines are a result of incomplete combustion of natural gas. Improperly tuned turbines operating at off design levels decrease combustion efficiency resulting in increased CO emissions. Control measures taken to decrease the formation of NO_X during combustion may inhibit complete combustion, which could increase CO emissions. Lowering combustion temperatures through premixed fuel combustion can be counterproductive with regard to CO emissions. However, improved air/fuel mixing inherent to newer combustor design and control systems limits the impact of fuel staging on CO emissions.

Control Options Evaluated – The following control options were evaluated in the CO BACT review:

High-temperature CO oxidation catalyst
Good combustion control

Discussion – The most stringent control for CO on a combustion turbine is a CO catalyst, which can remove up to 90 percent of CO in the flue gas. Oxidation catalyst technology does not require the use of additional chemicals for the reaction to occur. Rather, the oxidation of CO to CO_2 utilizes the excess air present in the turbine exhaust and the activation energy required for the reaction to proceed in the presence of the catalyst. Technical factors relating to this technology include turbine back pressure losses, unknown catalyst life due to masking or poisoning, greater emissions and reduced market responsiveness due to startup, and potential collateral increases in the emissions of SO_3 and condensible PM_{10}. Catalytic oxidation systems operate in a relatively narrow range of temperatures. Optimum operating temperatures for these systems is generally range from 700^{o}F to 900^{o}F. High temperature oxidation catalysts are rate up to 1,200^{o}F. Typical pressure losses across the oxidation catalyst reactor are in the range of 1.5 to 3.0 inches of water. Pressure drops at this range correspond to a 0.15 to 0.3 percent loss of power output for each 1.0 inch of water pressure loss. Like all catalyst systems, catalyst's are subject to loss of activity over time, and therefore most be considered in the overall cost and maintenance of the system.

A high temperature CO oxidation catalyst system cost effectiveness was also preformed for the proposed simple cycle operation. Based on vendor quotes and a annualized replacement cost calculated based on 3-year catalyst life, a cost per ton of CO removed was estimated at $6,500. This cost is well over that has been required by any proceeding BACT determinations.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the Unites States. The following table represents entries in the RBLC of similar operation:

Company	Facility	Throughput (per turbine)	Emission Rate (ppm@15%O2)	Control Description
Proposed Duke Knox Facility	Turbine (SC)	8 x 80 MW	25 (24 hour average)	Good Combustion
Duke Energy Madison, OH	Turbine (SC)	8 x 80 MW	25	Good Combustion
Wisconsin Public Service, WI	Turbine (SC)	1 x 102 MW	25	Good Combustion

Hardee Power Station, FL	Turbine (SC)	1 x 75 MW	20	Good Combustion
Enron, Des Plaines	Turbine (SC)	8 x 83 MW	25	Good Combustion
RockGen Energy, WI	Turbine (SC)	Not specified	12	Good Combustion
Southern Energy, WI	Turbine (SC)	4 x 170 MW	12	Good Combustion
Vermillion Generating Station, IN	Turbine (SC)	8 x 80 MW	25	Good Combustion

In regards to simple cycle projects, only the one (1) permit addressed above (Colorado Springs Utility), has been issued requiring an oxidation catalyst. This source did not have limitations on the hours of operation or fuel usage, such as the proposed project. Therefore without such limitations, the cost effectiveness value for the source discussed above would be much lower than the value determined for this proposed project. The cost effectiveness of this system was estimated to be less than $1,000 per ton of CO removed. This value is far less than the cost effectiveness value of $6,500, determined by the OAQ.

The cost per ton removed for most of the permitted simple cycle projects, referenced in the above table, range from $1,300 - $17,000. Additionally, two (2) simple cycle projects located in severe ozone non-attainment areas in Illinois (Wood River (7/99) and People Gas and Light (12/98)) were permitted without an oxidation catalyst at costs of approximately $2,000 per ton of CO removed.

When reviewing the combined cycle or cogeneration projects that have been permitted to use an oxidation catalyst, most control systems were required due to LAER determinations or to avoid LAER/PSD. Furthermore, the cost effectiveness values for the projects not required to use an oxidation catalyst system, range from $2,000 to $7,400 per ton of CO removed. These projects tend to not have limitations on the hours of operation or fuel usage, such as the proposed project. Therefore without such limitations, the cost effectiveness value for these projects would be much lower than the value determined for this proposed project.

If this source operated at 8,760 hours per year like the combined cycle and cogeneration projects discussed above that were required to use an oxidation catalyst system, the cost effectiveness value would much lower per ton of CO removed. This cost would be comparable to the other sources required to use an oxidation catalyst system and would be considered economically feasible by the OAQ. However, this source does not intend to operate 8,760 hours per year. This source is limited to a restricted fuel usage rate which is equivalent to 2500 hours per year. This limitation on the fuel usage rate yields a much larger cost effectiveness value, which is considered to be economically infeasible.

Catalytic oxidation is excluded from further BACT consideration due to the high cost associated with the control.

Good Combustion Control

The next type of control to consider is efficient combustion control design. From Table 3, the first combustion control emissions level ranges from 9 ppmvd to 15 ppmvd at 15% O_2 which is based on the use of the GE 7FA Dry Low-NOx (DLN) technology. Note that there is a range of permitted CO emission limits because different states have required different values. However, General Electric does guarantee a CO emission limit of 9 ppmvd at 15% O_2. General Electric has confirmed that CO emissions from the 7FA model are lower than the 7EA model due to differences in design. The main difference in design between the two models is the post flame temperature. The post flame temperature in the transition piece leading up to the first stage turbine nozzle is hotter in the 7FA than the 7EA. This hotter temperature results in burning out more CO emissions. Therefore, CO emissions from the 7FA turbines are not comparable and this emission limit is excluded from further BACT consideration.

Based on the table above, the next combustion control emissions level is 20 ppmvd at 15% O_2 based on the use of the GE 7EA DLN technology. This emission limitation has only been permitted in Florida for the Hardee Power Station, TECO Power Services. This emission limitation was below the vendor guarantee of 25 ppmvd at 15% O_2. The first year of operation the source will be permitted for 25 ppmvd at 15% O_2 and thereafter have to comply with a CO limit of 20 ppmvd at 15% O_2. Compliance with this limit will be determined by stack testing. The source will not be required to install a continuous CO emission monitoring system, unlike the project proposed. After discussing this project with the Florida Department of Environmental Protection (FDEP), the OAQ was informed that this emission limit was based off of emission data from the Kern River project. The OAQ then reviewed the emission data and project briefing supplied by the FDEP. The Kern River project consists of eight (8) combustion turbines and eight (8) heat recovery steam generators. The combustion turbines are older GE 7EA turbines with water injection to control NOx emissions to 42 ppmvd at 15% O_2. To comply with the Clean Air Act of 1990, the source converted their NOx controls from water injection at 42 ppmvd to DLN combustors at 16.4 ppmvd. The OAQ believes that these CO emissions are not comparable to this project because this project consists of hybrid machines that are currently not available on the market. In addition, this project is a combined cycle project whose CO emissions were determined by stack tests and not CEMS data. The OAQ determined, such as the case for NOx emission data, that the CO emissions data should be based on the new GE units currently being marketed. Therefore this emission limit is excluded from BACT consideration.

The combustion turbines proposed for installation at the new source, incorporates an efficient combustor design to minimize the CO emissions. The advanced dry low-NOx combustors of the turbines are guaranteed to maintain 25 ppmvd of CO at 15% O_2 in conjunction with natural gas, when operating loads above 60 percent. Since the source is using the dry low-NOx technology to minimize NOx emissions, CO emission will be increased. The OAQ does recognize that there is a Atrade-off@ between NOx and CO emissions from these units. Other facilities, as listed in Table 3, have been permitted with such emission limit as BACT. Currently, the OAQ has confirmed that GE cannot guarantee an emission limit lower than 25 ppmvd for the 7EA units.

<u>Conclusion</u> – Based on the information presented above, the CO BACT for the eight combustion turbines shall be the use of natural gas as the primary fuel, good combustion control, and a operational limitation of 2,000 hours per year firing natural gas. The CO emissions from each combustion turbine shall not exceed 25 ppmvd corrected to 15% O_2 on a twenty four (24) hour operating average. This is equivalent to 53.96 pounds of CO per hour.

The CO BACT for the eight combustion turbines, when firing diesel fuel, shall be good combustion control and a operational limitation of 500 hours per year firing diesel fuel. The CO emissions from each combustion turbine shall not exceed 25 ppmvd corrected to 15% O_2 on a one (1) hour average. This is equivalent to 42.96 pounds of CO per hour.

For periods of startup/shutdown each combustion turbine will be limited to 65.5 pounds of CO per startup and 58.9 pounds of CO per shutdown when firing natural gas. Each combustion turbine shall not exceed 76.4 pounds of CO per startup and 65.5 pounds of

CO per shutdown when firing diesel fuel. Also, the source will be limited to 240 startup/shutdowns per year.

(3) SO_2 BACT Review

Sulfur dioxide (SO_2) emissions are emitted from combustion turbines as a result of the oxidation of the sulfur in the fuel. SO_2 emissions are directly proportional to the sulfur content of the fuel.

Control Options Evaluated – the following control options were evaluated in the BACT review:

Flue Gas Desulfurization System
Use of Low Sulfur Fuels
Utilizing natural gas as the primary fuel

Discussion – A flue gas desulfurization system (FGD) is comprised of a spray dryer that uses lime as a reagent followed by particulate control or wet scrubber that uses limestone as a reagent. FGD is an established technology principally on coal fired and high sulfur oil fired steam electric generating stations. FGD systems have not been installed on natural gas fired combustion turbines because of technical and cost factors associated with treating large volumes of high temperature exhaust gas containing low SO_2 levels. FGD typically operates at an inlet temperature of approximately 400 to 500 ^oF. In addition, FGD systems are not typically effective for streams with low sulfur SO_2 concentrations such as natural gas fired sources. The concentration of SO_2 in the exhaust gas is the driving force for the reaction between SO_2 and the reagent. Therefore, removal efficiencies are significantly reduced with lower inlet concentrations of SO_2.

FGD systems also have energy and environmental impacts associated with their operation. A significant amount of energy is required to operate a FGD system due to the pressure drop over the scrubbers. There are also environmental impacts due to the disposal of the spent reagent and the high water use required for a wet scrubbing system. For the technical, energy, and environmental reasons presented above, FGD was excluded from further consideration in the BACT analysis

The use of low sulfur fuels is the next level of control that was evaluated for the proposed facility. Pipeline quality natural gas has the lowest sulfur content of all the fossil fuels. The NSPS established a maximum allowable SO_2 emission associated with combustion turbines and requires either an SO_2 emission limitation of 150 ppmvd at 15 percent oxygen or a maximum fuel content of 0.8 percent by weight (40 CFR 60 Subpart GG). Natural gas combustion results in SO_2 emissions at approximately 1 ppmvd. Therefore, the very low SO_2 emission rate that results from the use of natural gas as the primary fuel with low sulfur diesel fuel as a backup fuel represents BACT for control of SO_2 emissions from the combustion turbine.

Conclusion – Based on the information presented above, the SO_X BACT shall be the use of low sulfur natural gas as the primary fuel, low sulfur diesel as a backup fuel, and good combustion practices. The SO_X emission limit from each turbine when firing natural gas shall not exceed 0.0052 lb/MMBtu, which is equivalent to 6.02 pounds SO_2 per hour. Each combustion turbine when firing diesel fuel shall not exceed 0.0363 lb/MMBtu, which is equivalent to 42.04 pounds SO_2 per hour.

The proposed source will be limited to 2,000 operating hours per year when firing natural gas, and 500 operating hours per year when firing diesel fuel. These operational limitations for each combustion turbine are equivalent to 6.02 tons per year of SO_2 when firing natural gas, and 42.04 tons per year of SO_2 when firing diesel fuel. The sulfur content of the natural gas shall not exceed 2 grains per dry scf. The sulfur content of the diesel fuel shall not exceed 0.05 percent by weight.

(4) PM BACT Review

Particulate matter emissions from natural gas combustion sources consist of inert contaminants in natural gas, sulfates from fuel sulfur or mercaptans used as odorants, dust drawn in from the ambient air, particulate of carbon and hydrocarbons resulting from incomplete combustion, and condensibles. Units firing fuel with low ash content and high combustion efficiency exhibit corresponding low particulate matter emissions.

The three potential sources of filterable particulate emissions that can result from combustion sources are mineral matter found in the fuel, solids or dust in the ambient air used for combustion, and unburned carbon or soot formed by incomplete combustion of the fuel. There is no source of mineral matter found in the fuel for natural gas-fired sources. In addition, as a precautionary measure to protect the high speed rotating equipment within a combustion turbine, the inlet combustion air is filtered prior to introduction in the combustion turbine. Finally, the potential for soot formation in a natural gas-fired combustion turbine is very low because of the excess air combustion conditions under which the fuel is burned. Diesel fuel contains only trace amounts of ash.

There are two sources of condensible particulate emissions from combustion sources: condensible organics that are the result of incomplete combustion and sulfuric acid mist, which us found as sulfuric acid dihydrate. For natural gas-fired sources there should be no condensible organics originating from the source because the main components of natural gas (i.e. methane and ethane) are not condensible at the temperature found in the Method 202 ice bath. As such, any condensible organics are from the ambient air. The most likely condensible particulate matter from natural gas-fired sources in the sulfuric acid dihydrate, which results when sulfur in the fuel and the ambient air is combusted and then cools.

Control Options Evaluated – The following control options were evaluated in the BACT review:

Baghouse (Fabric Filter)
Electrostatic Precipitator (ESP)
Good Combustion

Technically Infeasible Control Options – Traditional add on particulate control, such as the above listed, have not been applied to natural gas and low sulfur diesel fuel fired combustion turbines. High temperature regimes, fine particulate and low particulate rates coupled with significant airflow rates make add on particulate control equipment technically infeasible.

Discussion – In order to reduce particulate emissions from a turbine assembly, combustion of clean burn fuels like natural gas and low sulfur diesel fuel is extremely beneficial. Based on the RBLC database, good combustion practice and combustion control have been listed as the means for reducing particulate matter emissions from all sizes of turbines. The implications of this control alternative are that the proposed project operators will maintain the turbine in good working order per manufacturers guidance and implement good combustion.

As stated above, the combustion of natural gas and low sulfur diesel fuel generates negligible amounts of particulate matter. There is a degree of variability inherent to the test method (Method 202) used to determine compliance with the proposed particulate limits. The variability from this test result is from several factors. First, there is such a large volume of exhaust gas stream compared to small amount of particulate. For example, the concentration of particulate matter could be the same for two gas steams, however, if one of the gas streams is at a lower flow rate the pound per hour emission rate would be less than a gas stream that is at a higher flow rate. Second, as with any test there is a possibility of human error, which have the potential to bias the test higher or lower than what is actually being emitted. In addition, the inlet air filters are not a hundred percent efficient, so any particulate that passes through the filters will also leave the exhaust stack. The higher the background concentration of particulate matter in the ambient air the more will pass through the combustion turbine stack. Ambient air particulate concentration can vary depending on location, activity in the area, and weather conditions.

Conclusion – Based on the information presented above, the PM/PM_{10} BACT shall be the use of natural gas as the primary fuel, low sulfur diesel as a backup fuel, and good combustion practices. The PM_{10} emission limit from each turbine when firing natural gas shall not exceed 0.0095 lb/MMBtu, which is equivalent to 11.0 pounds per hour of PM_{10}. Each combustion turbine when firing diesel fuel shall not exceed 0.0219 lb/MMBtu, which is equivalent to 25.01 pounds per hour of PM_{10}.

The proposed source will be limited to 2,000 operating hours per year when firing natural gas, and 500 operating hours per year when firing diesel fuel. These operational limitations for each combustion turbine are equivalent to 11.0 tons per year of PM_{10} when firing natural gas, and 6.25 tons per year of PM_{10} when firing diesel fuel.

(5) VOC BACT

The VOC emissions from natural gas-fired sources are the result of two possible formation pathways: incomplete combustion and recombination of the products of incomplete combustion. Complete combustion is a function of three variables; time, temperature and turbulence. Once the combustion process begins, there must be enough residence time at the required combustion temperature to complete the process, and during combustion there must be enough turbulence or mixing to ensure that the fuel gets enough oxygen from the combustion air. Combustion systems with poor control of the fuel to air ratio, poor mixing, and insufficient residence time at combustion temperature have higher VOC emissions than those with good combustion practice.

Control Options Evaluated – The following control options and work practice were evaluated in the BACT review:

Catalytic Oxidation
Good Design/Operation

Discussion – An oxidation catalyst designed to control CO would also provide control for VOC emissions. The level of control is dependent on the content of the natural gas. The same technical factors that apply to the use of an oxidation catalyst technology for control of CO emissions (narrow operating temperature range, loss of catalyst activity over time, and system pressure losses) apply to the use of this technology for collateral control of VOC emissions.

Since an oxidation catalyst was shown to not be cost effective for control of CO, it would not be cost effective for control of VOCs at a much lower emission rate (approximately 20 percent of the annual CO emissions) and lower control efficiency. An oxidation catalyst is therefore no longer considered BACT for the control of VOC emissions at the proposed facility.

Existing BACT Emission Limitations – The EPA RBLC is a database system that provides emission limit data for industrial processes throughout the United States. The table below represents similar operations that have been recently permitted.

Company	Facility	Throughput MMBtu/hr	Emission Limit lb/MMBtu	Control Description
Proposed Duke Knox Facility	Turbine	1158	0.0018	Combustion Control
Gorham Energy, ME	Turbine	2194	0.0017	Oxidation Catalyst
Carolina Power & Light, NC	Turbine	1908	0.0015	Combustion Control
Duke Power Lincoln, NC	Turbine	1247	0.004	Combustion Control
Duke Power Lincoln, NC	Turbine	1313	0.0015	Combustion Control
Alabama Power & Light	Turbine	1777	0.016	Combustion Control
	Duct Burner			
Lakewood Cogeneration, NJ	Turbine	1190	0.0046	Combustion Control
	Duct Burner	131	0.0017	
Auburndale Power Partners	Turbine	1214	6 lb/hr	Combustion Control
Berkshire Power Development, MA	Turbine	1792	6.3 lb/hr	Combustion Control
LSP-Cottage Grove, MN	Turbine	1988	0.008	Combustion Control
	Duct Burner			
Narragansett Electric, RI	Turbine	1360	5 ppm	Combustion Control
	Duct Burner			
Saranac Energy, NY	Turbine	1123	0.0045	Oxidation Catalyst
	Duct Burner	553	0.011	
Southern Energy, MI	Turbine	1000 MW	0.008	Combustion Control
	Duct Burner			
LS Power, IL	Turbine	1100 MW	0.012	Combustion Control
	Duct Burner		0.019	

The RBLC does not list any entries that require an oxidation catalyst for a combined cycle operation reviewed under PSD BACT. Also an oxidation catalyst would not be economically feasible because of the lower inlet CO emissions associated with new combustion technology. The Duke Knox facility offers the lowest VOC emission rate and is therefore considered BACT.

Conclusion - Based on the information presented above, the VOC BACT shall be the use of pipeline quality natural gas as the primary fuel, diesel as backup fuel, and good combustion practices. The VOC emission limit from each turbine when burning natural gas shall not exceed 0.0018 lb/MMBtu, which is equivalent to 2.08 pounds VOC per hour. Each combustion turbine when firing diesel shall not exceed 0.0117 lb/MMBtu, which is equivalent to 13.55 pounds per hour of VOC.

The proposed source will be limited to 2,000 operating hours per year when firing natural gas, and 500 operating hours per year when firing diesel fuel. These operational limitations for each combustion turbine are equivalent to 2.08 tons per year of VOC when firing natural gas, and 3.39 tons per year of VOC when firing diesel fuel.